Ontario

THE REPORT OF THE

Royal Commission on Electric Power Planning

Chairman: Arthur Porter

VOLUME 2

The Electric Power System in Ontario

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The Report of the Royal Commission on Electric Power Planning

List of Volumes

The Report of the Royal Commission on Electric Power Planning is comprised of the following volumes:

Volume 1: Concepts, Conclusions, and Recommendations

Volume 2: The Electric Power System in Ontario

Volume 3: Factors Affecting the Demand for Electricity in Ontario

Volume 4: Energy Supply and Technology for Ontario

Volume 5: Economic Considerations in the Planning of Electric Power in Ontario

Volume 6: Environmental and Health Implications of Electric Energy in Ontario

Volume 7: The Socio-Economic and Land-Use Impacts of Electric Power in Ontario

Volume 8: Decision-Making, Regulation, and Public Participation: A Framework for Electric Power Planning in Ontario for the 1980s

Volume 9: A Bibliography to the Report

VOLUME 2

The Electric Power System in Ontario

Sushil Choudhury

The Author

SUSHIL CHOUDHURY was born in India and obtained a degree in electrical engineering there in 1972. He did graduate work in control systems at the University of New Brunswick where he obtained an M.Sc.E. degree in electrical engineering in 1974. After that he obtained an M.A.Sc. degree in industrial engineering from the University of Toronto; his thesis for that degree concerned the long-term planning of the electric supply system in Canada. In January 1977, he joined B.C. Hydro in Vancouver, where he worked on system planning projects. In January 1978, he was seconded to the Commission. Mr. Choudhury is a member of the Institute of Electrical and Electronics Engineers and is a registered professional engineer in Ontario. He has published several technical papers in the areas of control systems, power devices, and electric supply system planning.

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Foreword

The Commission wishes to acknowledge the contributions to our Final Report made by the author of this volume. The enormity of the task as well as the skill and tenacity with which it was performed are testimony to the talents of Sushil Choudhury. Our work would have been immeasurably more difficult without his assistance.

This volume, *The Electric Power System in Ontario*, focuses on a key issue area raised by the public during the Commission's public hearings process. The analysis, conclusions, and recommendations reflect data received by the Commission in the form of public testimony and exhibits, consultants' reports, and independent research and analysis by the author. We have relied heavily on this work in formulating our own conclusions and recommendations in Volume 1. However, the views expressed in this volume are ultimately the responsibility of the author. This document is therefore best viewed as a background paper which attempts to draw together the detailed evidence and analysis available on this complex subject, in a fashion which will be of use to the general public as well as to the technical community.

The research and evolution of this document were directed and reviewed for the Commission by Philip A. Lapp and Peter G. Mueller.

Arthur Porter, Chairman.

Executive Summary

The objective of this volume is twofold – to illustrate the concepts that are essential to the operation and planning of a large electric power system, and to discuss the issues that are related to the technical aspects of Ontario's electric power system. As the first of the supporting volumes of the Commission's Report, this volume provides a comprehensive description of Ontario's electric power system, with the idea that this will make it easier to understand the economic, socio-environmental, and other broad issues that are discussed in the subsequent volumes.

The technical aspects of Ontario's electric power system are discussed in terms of the mix of generating resources, system reliability, the interconnections with other systems, and the operation and control of the system. Also discussed is the probable impact of alternate technologies on the planning of the system by the end of this century.

The mix of generating resources in an electric power system is affected by many factors, important among which are cost, reliability and performance, operating characteristics, fuel requirements and supply, lead time, and total-system considerations. For base-load applications, a new CANDU nuclear station has a significant economic advantage over a new fossil station fuelled either by U.S. coal or by western Canadian coal. The economic comparison between coal and nuclear is not very sensitive to changes in various parameters such as the cost of geological disposal of spent nuclear fuel, discount rate, uranium prices, etc. Oil- and gas-fired plants are economic only for peaking and reserve. The operating performance of the CANDU units indicates that they will be able to maintain base-load capacity factors. While CANDU units are not suitable for load-following, they are capable of shut-down on weekends and of operation at reduced output overnight.

Ontario Hydro's fuel supply up to the end of this century appears to be reasonably secure. Its coal requirements in the late 1990s are not expected to be much higher than the current consumption levels; in the 1980s there will be a problem of over-supply of coal. No problem is foreseen in meeting the peaking and reserve requirements of residual oil- and gas-fired stations. Hydro's current uranium contracts are adequate for the 30-year requirements of about 5,400 MW of uncommitted nuclear capacity to be installed after the Darlington G.S. This is sufficient for capacity additions at least until the mid-1990s. Although the lead time of a major generating facility could be reduced from 13 to eight years by site-banking, there is no urgency about doing this. Sufficient time is available for public participation and environmental assessment of any new site proposal by Hydro.

A major total-system consideration in the choice of a generating mix is the desirability of a diverse mix to increase the system's resilience and flexibility. Although economics is the major consideration in Ontario Hydro's planned generating mix, operating limitations and fuel diversity are also important. Therefore, the planned long-term share of nuclear capacity is lower (at about 50 per cent) than that suggested by economic considerations (about 60 per cent). The role of storage schemes, such as underground pumped storage, in enhancing the operating flexibility of CANDU units when faced with lower-than-expected load growth is limited, because their lead times are likely to equal those of a nuclear plant.

The assessment of the reliability of an electric power system such as Ontario's is extremely complex and difficult. Studies that have been undertaken by Ontario Hydro indicate that Hydro is a front-runner among electricity utilities in its efforts to determine a justifiable level of system reliability and thus to advance the state of the art of reliability assessment. Hydro has developed a generation reliability programme based on the frequency-and-duration-of-outages (F&D) method. The F&D technique is considered to be far superior to the widely used loss-of-load-probability method. Hydro, along with its neighbours, is also active in developing practical schemes for the quantitative evaluation of transmission reliability. Because of the complexity of these schemes, it will be some time before they find widespread use among electricity utilities. Experience in Ontario indicates that the contribution of failures in the bulk power system to interruptions of supply to customers has been small. Most interruptions occur because of failures in the distribution system.

As a result of recent studies undertaken by Ontario Hydro to match the costs and benefits of reliability, Hydro has reduced its planned generation reserve from about 30 per cent to 25 per cent of the firm peak. The reserve requirements, expressed as a percentage of the primary peak, are only about 17 per cent, representing an 8 per cent reduction in capacity by load management. The combined effect of the

reduced reliability criterion and load management is a reduction in system capacity requirement in the year 2000 by the equivalent of one station the size of Nanticoke.

Ontario's interconnections with its neighbours (Quebec, Manitoba, Michigan, and New York) have served their purpose well. They have demonstrated that their benefits far outweigh their costs. Strong interconnections tend to increase a system's resiliency. This and a number of other considerations suggest the desirability of increasing electricity interchange, not only in absolute terms, but also relative to total domestic demand. Ontario Hydro has a substantial surplus in generating capacity that is expected to continue until the early 1990s. It is in Ontario's interests for Hydro to make profitable sales from this surplus, especially to its U.S. neighbours. The sheer size of the U.S. market, its heavy reliance on oil-fired generation, and the delays encountered by U.S. utilities in commissioning coal-fired and nuclear plants suggest a continuing market for Ontario's surplus. Also, Hydro's system is larger and more diversified than those of any of the neighbouring U.S. utilities, which are mostly investor-owned, profit-oriented, fragmented, and subject to capital constraints and taxation on income.

Power-transfer capability with the U.S. is projected to decline sharply as internal transmission in southern Ontario becomes fully dedicated to domestic loads. To take advantage of the export opportunities, construction of major new transmission facilities in eastern and southwestern Ontario is required.

Strengthening interconnections with Manitoba and Quebec will require comprehensive agreements between the provincial and federal governments as well as between the electricity utilities. Such interconnections will tend to accelerate the development of Canada's remaining hydroelectric potential (for example, the Nelson River in Manitoba) and will take advantage of the increasingly complementary nature of the largely hydraulic systems in Quebec and Manitoba and the increasingly thermal system in Ontario. A proper evaluation of firm hydraulic purchases from Quebec and Manitoba can only be made in a broad provincial total-energy framework.

The strengthening of the transmission system in eastern Ontario, especially for the supply to Ottawa, is urgently needed. This will also facilitate electricity interchange with Quebec and New York. In southwestern Ontario, the objectives of incorporating Bruce B, supplying future loads, and strengthening the transmission network and the interchange capability with the U.S. can best be met, from a purely technical viewpoint, by constructing a 500 kV line from Bruce to London. However, there are socio-environmental and land-use implications of such an alternative that must be fully investigated.

The emergent technologies that are expected to have the maximum direct impact on Ontario's electric power system before the end of the century are load management, electric energy storage, co-generation, and generation from biomass- and refuse-derived fuels. Ontario Hydro's participation in load management with the municipal utilities over the next few years is worthy of support because it will provide the needed assessment of the cost and the public acceptance of load management. Hydro's target for managed load by 1992 is 1,300 MW. This target will have to be reassessed in the light of the experience gained in the 1980s with load management and in the light of other ways of meeting the peak load, such as peaking hydraulic and storage. Among the various alternatives for large-scale storage, underground pumped storage appears to be the most economical. The economic justification for developing storage will depend on the need for new peaking capacity and the availability of surplus nuclear energy for pumping. Hydro's system could accept from 0 to 2,000 MW of pumped storage by the late 1990s, based on an average annual rate of load growth of from 3 to 4.5 per cent.

The growth of co-generation in Ontario will be influenced greatly by the nature of the financing, the price of boiler fuels, and the price of electricity purchased from Ontario Hydro. Any growth in industrial co-generation will tend to replace Ontario Hydro's base-load requirements. Parallel operation of many small co-generators with the Ontario Hydro system will increase the complexity of overall system operation. However, many small co-generators will tend to reduce overall system reserve requirements and the stand-by charges faced by the co-generators. Co-generation has the added advantages of more efficient utilization of fossil fuels, diversification, and decentralization.

Central wood-fuelled generation is not economic at present in comparison with coal-fired and CANDU nuclear generation. Although the municipal refuse generated in Ontario has a potential to produce about 3.5 per cent of Ontario's demand for electricity, it is more likely to be used both to generate electricity and provide district heat. Utilizing the energy potential of refuse is one of the best ways to solve the waste-disposal problem and provide some diversity and security in the fuel base, by making use of an indigneous, renewable, and cheap source of energy.

CHAPTER ONE

Introduction

The electric power system in Ontario is one of the largest and most sophisticated power systems in the world. It has been supplying the growing demand for electricity in the province with a high degree of reliability and at reasonable cost since the early part of this century. The system is for the most part identifiable with Ontario Hydro, which supplies more than 90 per cent of the province's demand for electric energy. The remainder is either supplied by privately owned utilities, notably the Great Lakes Power Corporation and the Canadian Niagara Power Company, or generated by industrial establishments for their own use. In 1978, Ontario Hydro supplied approximately 90 billion kW·h to 334 municipal utilities, 785,000 rural customers, and 100 large industrial users. Its power system comprises approximately 23,000 MW of generating capacity, based on a variety of primary energy sources, and 32,000 km of transmission and distribution lines of various voltages, serving Ontario's population of eight million. For planning and administrative purposes, Ontario Hydro's system is conveniently divided into two systems which are connected by a single tie-line. The East System, by far the larger and serving the geographic regions of southern, eastern, and northeastern Ontario, is an integrated grid system, while the West System, serving the northwestern regions of the province, is essentially a linear system. The dividing line between the two systems runs north-south through the community of Wawa, north of Sault Ste. Marie. However, electrically, the two systems operate in synchronism as one system.

The Scope of This Volume

The objective of this volume is twofold. First, to illustrate the basic concepts that are vital to the planning and operation of an electric power system, and, second, to discuss the issues that are related to the technical aspects of electric power planning in Ontario. As the first of the supporting volumes of the Commission's Final Report, this volume provides a comprehensive description of Ontario's electric power system, in the hope that the economic, socio-environmental, public-participation, and other issues discussed in the subsequent volumes may then be better understood. For example, the issue of the use of land for transmission lines can be seen in perspective only after recognition of the role of transmission lines in a total power system, and the public's involvement in the decision-making process must be assessed in the light of the complexity of an electric power system.

Most of this volume is devoted to the technical considerations relating to the electric power system, such as reliability, operation and control, and fuel requirements, because these are the first to affect the design of a system. The broader social, economic, environmental, and political considerations are the subjects of other volumes. Since it is impossible, and indeed impractical, to isolate them from technical considerations, some overlap is inevitable.

The majority of the issues the Commission faced, related to bulk power transmission planning in Ontario, were socio-economic or socio-environmental. Therefore, bulk power transmission is discussed here to the extent that it is vital to an understanding of the overall design of the system. For example, in any consideration of system design, the security of bulk power transmission is pivotal. Among the generation alternatives analysed in detail in this volume are the ones that are conventionally used in the province and have the potential for large-scale development in the 1980s and 1990s. New and emergent generation technologies are described in Volume 4. However, some of them, with a potential to affect system planning and operation in this century, are examined in this volume.

RCEPP Issue Paper No. 7

Many of the issues that are discussed in this volume were raised during the Commission's public information hearings (April 1976 to January 1977) and subsequently summarized in the Commission's Issue Paper No. 7, entitled "The Total Electric Power System", published in April 1977. The issues were listed according to four characteristics of a total power system, identified by the Commission as reliability, operational concepts, the mix of generating stations, and interconnections. The following is an outline of that issue paper and of the issues that are considered in this volume.

Reliability

A high level of reliability is a most desirable feature of an electric power system. A factor that enhances reliability is a total-system configuration that is flexible and resilient. A multiplicity of generating stations rather than a single massive one and a network of transmission and distribution systems rather than a single ultra-high-capacity link make a system less vulnerable to the effects of component breakdowns and outages. Other factors that enhance system reliability are an adequate generating reserve, a secure bulk power transmission and distribution system, optimal system operation and control, and interconnections with neighbouring systems.

Some issues that are relevant to reliability are: What is the impact of various planning factors on system reliability? In order to balance the costs of high levels of reliability against their benefits, to what extent could the generation reserve requirements be reduced? What is the role of load management in reserve reductions? Are Ontario Hydro's reliability evaluation and assessment techniques adequate? These issues are discussed in Chapters 4, 7, and 8.

Operational Concepts

Because of varying demand patterns, generating units are operated in one or more of the following four modes: base load, intermediate load, peaking, and reserve. The cost economics of the resources available in Ontario make nuclear plants suitable for base load, coal-fired plants suitable for base and intermediate loads, and oil- and gas-fired units suitable for peaking and reserve. Hydraulic plants are well suited for any of these modes but this versatility is constrained by the limitations on water availability. Reliable and economic operation of a system such as Ontario Hydro's requires a sophisticated, computerized information monitoring and control system. Some of the issues concerning operational aspects are: the potential for load management and energy storage for peak shaving, the operational implications of centralized and decentralized generation, and the impact of alternate generation sources such as industrial co-generation. The operational concepts and issues are discussed in Chapters 6 and 8.

The Mix of Generating Stations

A diverse mix of components is often desired in any complex physical system so that a catastrophic breakdown of a single major component does not necessarily lead to the failure of the total system. This also applies to the mix of generating resources for an electric power system. In Ontario, the existing mix includes hydroelectric, nuclear, and coal-, oil-, and gas-fired stations. In 1978, hydroelectricity supplied about one-third, coal and nuclear generation approximately one-fourth each, and gas, oil, and purchases the rest of the electric energy demand. The choice of a particular mix is determined by factors such as cost, efficiency, the security of fuel supplies, operating limitations, environmental consideration, and the availability of suitable sites. Some of the related issues are: the cost-competitiveness of nuclear and coal-fired stations; the reliability and performance of Ontario Hydro's large thermal units; the future availability of fuels and heavy water; the lead times of large centralized generation facilities; and the impact of load management, energy storage, and co-generation on future generating mix. These issues are discussed in Chapters 3, 7, and 8.

Interconnections

The purpose of interconnections among electric power systems is to exchange power in emergencies or for reasons of economy. Ontario Hydro is linked with Hydro-Québec and Manitoba Hydro in Canada and with the New York and the Michigan Power Pools in the U.S. Interconnections enhance reliability and reduce reserve requirements by facilitating emergency exchanges of power and by taking advantage of the seasonal and time-zone diversity in the loads of the neighbouring systems. Interconnections may also reduce or delay the need for additional generating capacity, through arrangements for firm power imports. Some of the major issues raised by interconnections are: the potential for export of Ontario Hydro's surplus generating capacity in the 1980s; the implications of reliance on imports of hydroelectric power from Quebec and Manitoba in the 1990s; the implications of strengthening Ontario Hydro's interconnections with its neighbours; and, the role of intra-provincial interconnections. Chapter 5 discusses these issues.

Outline of This Volume

This volume comprises eight chapters supplemented by three appendices. Chapter 2 introduces the concept of an interconnected power system and its major components – generation, bulk power transmission, distribution, and end use. It does this by tracing the journey of electricity from its production from primary energy sources to its ultimate disposal. The various generation and transmission technologies that are at present available are described briefly. Also illustrated are the concepts of load factor, capacity factor, and load-duration curve, which are central to the planning and operation of a power system.

In Chapters 3, 4, 5, and 6, the four characteristics of the electric power system in Ontario that were identified in RCEPP Issue Paper No. 7 are discussed. These are generating mix, reliability, interconnections, and operation and control. Chapter 3 illustrates the important distinction between the mix of capacity and the mix of energy resources and provides a comparative analysis of factors associated with various technologies that affect the choice of a mix in Ontario. Among the factors considered are costs, reliability, operating characteristics, fuel requirements and supply, lead time, and total-system considerations such as resiliency and flexibility.

Chapter 4 considers the reliability of an electric power system. Starting with the traditional approaches to reliability evaluation, such as availability and security, this chapter underlines the difficulty of assessing a desired level of reliability, because of the complex nature of a power system. The effect on reliability of such factors as the outage rate of a generating unit, unit size, and interconnections with other systems is explained. Finally, the chapter describes the efforts of Ontario Hydro to advance the state of the art in reliability evaluation and assessment.

Chapter 5 deals with the interconnections between Ontario Hydro and its neighbours. After commenting on the outlook for electricity trade in the light of Hydro's projected surpluses, it reviews the conclusions and recommendations of two recent studies, dealing with the Canada-U.S. and interprovincial interconnections, respectively. Finally, a brief description of the interconnections between Ontario Hydro and other smaller members of the province's electric power system is included to underline the role of those members in Ontario's electric power planning.

In Chapter 6, the basic concepts that govern the operation and control of an electric power system are presented. The functions and responsibilities of the various levels of management and of the operational control hierarchy for a smooth day-to-day operation of the total system are discussed. The distinction between the electrical operation and the economic operation of a power system is explained.

Chapter 7 analyses the long-range planning considerations used by Ontario Hydro in the past and summarizes recent developments affecting these considerations, the utility's current expansion plans, and implications of a low-growth scenario. The chapter considers the methodology of Hydro's System Expansion Program Reassessment Study and the general nature of the results. Also presented are some technical considerations relating to the future of bulk power transmission in Ontario.

Finally, in Chapter 8, the impact of some potential alternate technologies on the operation and planning of the electric power system in Ontario is assessed. Among the technologies considered are load management, energy storage, co-generation, and biomass and refuse-derived fuels.

Appendix A gives a station-by-station listing of Ontario Hydro's generating resources. Appendix B outlines the characteristics of the conventional generating technologies in Ontario that affect the choice of a generating mix, and Appendix C discusses some technical considerations that relate to Ontario Hydro's interconnections with its neighbours.

CHAPTER TWO

The Electric Power System and Its Components

The Concept of a Power System

Electric energy does not occur in nature in a form in which we can use it. It must be converted from a primary source of energy such as falling water, coal, uranium, oil, or natural gas. The process of conversion is called generation. After being generated, electric energy flows over miles of bulk power transmission and distribution lines, and undergoes a series of voltage transformations before it is ultimately used in our homes, industries, and commercial buildings. The utilization of electric energy at a point of use, or for a type of use, is generally referred to as "electrical load". An electric power system may be defined as a number of generating stations and a multitude of customer loads interconnected through a network of transmission lines, transformer stations, and other transmission and distribution installations. The essential quality that makes this collection of apparatus a power system is that every one of its generating stations contributes to the supplying of every customer load.

The existence of large power systems may be explained by two qualities that customers value in their supply – reliability and economy. Power systems enhance the reliability of supply to the consumer. All power plants have to be taken out of service from time to time, either because of unscheduled shutdowns or for scheduled maintenance. If each load centre were supplied by a single nearby generating plant, few bulk power transmission lines would be needed, but there would be a complete local black-out every time a plant had to be shut down. Without a bulk power transmission network, the only way to avoid this would be to duplicate the plant at each load centre. This would be costly and it would still not guarantee a continuous supply of electricity, because the two plants might have trouble simultaneously, either by coincidence or by common cause. With a bulk power transmission network that is fed by several generating stations, much greater reliability of the total system can be realized with a much smaller reserve of generating capacity. Table 2.1 illustrates this concept. It considers 10 customer loads, each of 10 MW. In case 1, each load is supplied by its own isolated generators and the probability of generation deficiency with a 100 per cent reserve capacity is 1 per cent. In case 2, however, when all loads and generators are interconnected, the probability of generation deficiency with a generating reserve of only 50 per cent drops to 0.225 per cent.

Table 2.1 Illustration of the Improvement in Reliability in a "Power System"

Case 1: Individual Generator – Load Arrangement
Load: 10 MW
Generation: 2 × 10 MW units, each with a 10 per cent probability of failure
Reserve: 100 per cent
Probability of not meeting load: 1 per cent
Reliability: 99 per cent
Case 2: Power System
Load: 100 MW
Generation: 15 × 10 MW units, each with a 10 per cent probability of failure
Reserve: 50 per cent
Probability of not meeting load: 0.225 per cent
Reliability: 99.775 per cent

Source: RCEPP.

Power systems also provide considerable economy over the alternative arrangement, in which single generating stations serve only certain dedicated loads. The nature of individual loads is such that their peaks do not occur at the same time. This diversity causes the aggregated load to have a peak that is
Fig. 2.1. p. 15 lower than the sum of the peaks of the individual loads, as illustrated in Figure 2.1. This allows a power system to have less overall generating capacity than the sum of all the individual generating capacities that would be required to serve individual loads separately. Also, because the overall load is greater in a power system than it is for individual customers, the power system can incorporate larger generating units, offering economies of scale. Power systems also permit significant cost savings in the operation of the system. Ontario Hydro's system has various kinds of generating plants – hydroelectric; coal, oil,

gas, and uranium steam-electric; and combustion turbine plants. Hydroelectric plants have no fuel costs, and nuclear plants generate electricity at substantially lower fuel costs than fossil-fuelled plants. During the off-peak periods, great cost savings can be made by supplying the entire system from such stations. This can only be done with an extensive bulk power transmission network.

Power and Energy

The term electricity is quite often used as a substitute for both "electric power" and "electric energy". However, the distinction between power and energy must be clearly understood. Engineers and scientists use "power" when referring to the rate of flow of "energy". For example, an electric heater left half-on for two hours will heat a well-insulated room to the same temperature as the same heater left full-on for one hour. This means that the amount of electric energy consumed is the same in both cases, but in the second case the power level, i.e., the rate at which the electric energy is being consumed, is doubled.

The relationship between power and energy is well demonstrated by the electricity meter in your home. Inside this meter is a large thin circular disc that rotates and drives a series of registers that count its rotations. The disc rotates slowly when a small amount of electricity is being used, and more rapidly when the demand is heavier. The rate of rotation of the disc is a measure of the rate at which electric energy is being used, i.e., of the level of power being supplied. The total number of rotations of the disc in a given period is a measure of the electric energy that has been consumed. Thus, power is measured at an instant in time; a unit of power does not have the dimension of time in it. In contrast, the measurement of energy must be done over a period of time – a minute, an hour, or a year.

Electric power is often measured in kilowatts (kW) and electric energy in kilowatt hours (kW·h), a kilowatt hour being the amount of electric energy consumed when a device of 1 kW power rating is switched on for one hour, or one of 0.5 kW for two hours, or one of 10 kW for six minutes. Since one of the most commonly available primary sources that is used to generate electric energy is thermal energy, it is useful to consider the relationship between the kilowatt hour and commonly used units of heat such as the British Thermal Unit (BTU) and the kilocalorie (kcal).

When a kilowatt hour of electric energy is converted into heat at 100 per cent efficiency, e.g., in resistance heating, it produces 3,412 BTU or 860 kcal of heat. However, the number of British Thermal Units required to produce 1 kW·h of electric energy is significantly higher than 3,412, due to the limited conversion efficiency of heat engines. For example, a large modern coal-fired steam-thermal generating station has an efficiency of about 38 per cent, which means that, to produce 1 kW·h of electric energy, approximately ($3{,}412 \times 100/38 =$) 9,000 BTU of heat energy in coal is required. The kilowatt hour is also a unit of mechanical work, but it is not commonly used for that. The basic unit of work is the joule, which is equivalent to a watt second. Thus 1 kW·h is equivalent to 3.6 megajoules (MJ).

Since, at present, electric energy cannot be stored economically in large quantities, the concept of power is important for electric power systems. It is related to the capability of a system to meet the customers' demand for electric energy at the power level they desire and when they desire it. Power may be used at a certain level only infrequently, and then only for short periods. The electric supply system (generation, transmission, and distribution) and the wiring in any house must be designed to handle the maximum power level required or specified.

Power and energy are also related through the cost economics of the various generation technologies that are available. The capital cost of a plant is related to its capacity, or maximum power capability. The cost of energy production is, essentially, the cost of the fuel used. Thus for power demands of very short duration (i.e., with a small energy demand), the plants with the lowest capital cost are used. Combustion turbines fall into this category and are quite commonly used for short-duration applications. For power demands that occur virtually continuously (i.e., with a large energy demand), on the other hand, plant selection criteria emphasize lowest total cost (fuel as well as capital). High-capital-cost plants may satisfy this requirement if their fuel costs are quite low. In Ontario, hydraulic and nuclear plants fall into this category. The methods of cost minimization for power demand levels of various durations will be explained in Chapter 3.

The Components of an Electric Power System

The journey of electricity in a power system, from its production from primary fuels to its ultimate disposal, comprises four major steps – generation, high-voltage bulk power transmission, distribution, and end use. The components of an electric power system will be considered under those four headings.

Fig. 2.2: p. 16 A schematic representation of Ontario Hydro's power system is provided in Figure 2.2. The "area supply" and "subtransmission" stages shown in Figure 2.2, the two additional voltage transformation steps between generation and end use, are indicative of the size and spread of Ontario Hydro's system.

The Generation of Electric Power

The most commonly used techniques for the generation of electricity are hydroelectric, steam-thermal electric, and combustion turbine. In a typical hydroelectric generating plant, rivers fed by rain or melting snow are dammed to form a reservoir. When the stored water is allowed to flow from the surface of the reservoir through a hydraulic turbine at a lower elevation, the potential energy in the water is converted into kinetic energy, by falling, and then into mechanical energy, by the turbine. An electricity generator connected to the turbine shaft rotates and converts this mechanical energy into electric energy. The water continues its downward flow, to other reservoirs or directly into the lakes or oceans.

Hydroelectric plants have some important advantages over thermal plants. The fuel, that is, the gravitational potential energy supplied by the sun, is free and renewable. Hydroelectric conversion is a one-step conversion of mechanical energy to electric energy with greater than 90 per cent efficiency. Further, there is no emission of pollutants and no need for cooling water. Hydroelectric plants also have considerably longer lives (about 70 years) than thermal plants (about 40 years) and have much higher reliability. However, they may suffer from the disadvantage of having an adverse impact on the local environment, that is, ecology, aquatic life, and scenic beauty.

A variant of the hydroelectric generation concept, called pumped storage, is the only practical method at present for large-scale storage of electric energy. Pumped storage plants have been made possible by the development of highly efficient reversible pump-turbines and motor-generators. During off-peak hours, surplus electricity from low-fuel-cost plants is used to pump water from a low elevation to a storage reservoir above the station. When the demand increases, this water is released and used to generate electricity, as a substitute for some much more expensive form of peaking generation. The overall efficiency of a pumping-generating cycle is about 70 per cent.

In steam-thermal electricity generation, electricity is generated from the stored energy in a fuel such as coal, oil, natural gas, or uranium, through the production of steam. By the fission of uranium-235 in a nuclear reactor, or by the burning of fossil fuel under a boiler, heat energy is produced, and this heat energy is used to convert water into high-pressure and high-temperature steam. The steam is expanded in a series of steam turbines, causing the turbines, and an electricity generator connected to their common shaft, to rotate and produce electricity. By the time the steam leaves the turbines, it has been considerably reduced in temperature and pressure, but it is still quite hot. A heat exchanger condenses the steam back into water by transferring much of its heat to a body of cold water called cooling water. The condensate is then pumped back into the boiler to start the next cycle.

Fig. 2.3: p. 17 Figure 2.3 shows the steam cycle for a modern fossil-fuelled generating station. The thermal efficiency of a steam cycle is defined as the ratio of useful energy output, i.e., electric energy, to thermal energy input. Figure 2.3 shows that the efficiency of a fossil-fuelled station is about 37 per cent, 63 per cent of the energy in the fuel being dissipated as "waste" heat to the atmosphere, to cooling water, and to other heat sinks.

The steam cycle in a nuclear power plant is also explained by Figure 2.3. Instead of a boiler, there is a nuclear reactor in which uranium is "burned". The heat of the fission reaction is transferred to water to convert it into steam, either directly, as in a boiling-water reactor (BWR), or through a heat transport liquid such as heavy water, as in a CANDU reactor. There is little heat loss to the atmosphere in a nuclear plant. Also, the steam entering the turbine is at a considerably lower temperature in a nuclear power plant than in a fossil-steam plant. In a CANDU reactor, the steam temperature is about 250°C, compared with about 540°C in a fossil-steam plant. The lower steam temperatures of nuclear plants limit their thermal efficiency to about 30 per cent. Since only a negligible amount of the waste heat is dissipated to the atmosphere, the remaining 70 per cent must be discharged to the cooling water.

In a combustion turbine cycle, air is compressed, and this high-pressure air is mixed with fuel and fed

into a combustion chamber, where it is ignited. The resulting high-temperature gaseous combustion products are expanded in a gas turbine, causing it to rotate and drive an electricity generator. The air compressor is also driven by the turbine. In a simple cycle, the gas, after expansion in the turbine (although still quite hot), is discharged into the atmosphere. In a heat-recovery cycle, the exhaust gas is sent back to "preheat" the incoming air-fuel mixture before being discharged into the atmosphere. The efficiencies of the simple and heat-recovery cycles are 27 per cent and 33 per cent, respectively. Since the moving parts of a gas turbine are exposed directly to the combustion products, fuels with corrosive properties should not be used. The most commonly used fuels are distillate oil and natural gas. Ontario Hydro uses No. 2 distillate oil in its combustion turbine plants.

When the heat in the hot exhaust gases from a gas turbine plant is transferred to a steam boiler to raise steam for use in electricity generation, such an arrangement is called a combined-cycle plant. Interest in such plants has grown in recent years because of their potential for efficiencies higher than those of the large fossil-steam plants. The use of exhaust gases from gas turbines for steam production is, however, not new. In the southwestern United States, the petrochemical industry utilizes this concept to help satisfy the demand for electric energy as well as for process-steam. The General Electric Company and the Westinghouse Corporation are the leading exponents of the combined cycle in North America. Many utilities in the U.S. have combined-cycle capacity, either installed or under construction. Operating experience with these installations will have a significant effect on the extent to which combined-cycle plants will be used in future utility systems.

In Ontario, Ontario Hydro supplies more than 90 per cent of the provincial demand for electric energy. The remainder is provided by a number of small private utilities, for example, the Great Lakes Power Corporation, the Canadian Niagara Power Company, and the many industrial establishments that have hydraulic and thermal generating facilities for their own use. Many of the industrial thermal plants are used in a co-generation mode to supply process-steam as well as electricity.

Until 1951, Ontario Hydro's generating system was based exclusively on hydroelectric stations. In 1951, the first two coal-fired thermal-electric generating stations, the 1,200 MW Richard L. Hearn Generating Station (GS) on the Toronto waterfront and the 264 MW J. Clark Keith GS at Windsor, were put in service. Since then, Ontario Hydro has added four more coal-fired stations and one residual oil-fired station to its system, bringing its total fossil-fuelled capacity to about 12,000 MW. Hydro began its nuclear power programme in 1962 with the incorporation of the 22 MW Nuclear Power Demonstration GS of the CANDU design into the provincial power grid. In 1967, the 200 MW Douglas Point Nuclear GS on the shore of Lake Huron was brought on line. Hydro's first large-scale CANDU plant is the 2,000 MW Pickering GS outside Toronto which began feeding power into the provincial grid in 1971. A 3,000 MW CANDU nuclear station was recently added to the system at the Bruce Nuclear Power Development complex near the Douglas Point GS.

Appendix A provides a station-by-station listing of all of Ontario Hydro's generating resources, existing, under construction, and committed. The present system represents a balanced mix of the three primary energy sources that are available to the province – water power, uranium, and fossil fuels. In 1978, these sources each supplied roughly one-third of the provincial electric energy demand. Coal, imported from the U.S., was responsible for most of the electricity generated from fossil fuels.

All of Ontario Hydro's steam-thermal generating stations are located along the shores of the Great Lakes. As already noted, between 50 and 70 per cent of all the heat produced in a thermal power plant is rejected to cooling water. The Great Lakes provide a relatively inexpensive source of cooling water for this purpose. The cooling of Hydro's generating stations is based on the "once-through" cycle; cold water is drawn from the lake, circulated through steam condensers, and returned to the lake at a higher temperature. The difference in temperature between the incoming and the outgoing water is in the order of 10°C. The cooling of a 3,400 MW nuclear plant would require about 10 million litres of cooling water per minute. That is to say that each kilowatt hour of electric energy generated requires about 180 litres of cooling water.

Other methods of cooling are cooling towers and cooling ponds. In cooling towers, the warm water from thermal station condensers is circulated and brought into contact with the ambient air, to accomplish the heat exchange. Cooling towers are quite common in the U.S. and in Europe. Cooling towers tend to be monstrous in size – in the order of 400 feet high with an equally large base diameter – and about twice as expensive to build and operate as once-through cooling systems.

Cooling ponds are similar in concept to cooling systems using natural lakes or reservoirs except that

they tend to be smaller and they are sometimes man-made. Warm water is discharged into the pond, it spreads over the surface and is cooled, largely by evaporation, and then it is returned to the plant. Because of their low heat-transfer rates, cooling ponds require a considerable area of land – approximately one to two acres per megawatt of generating capacity. The size of the pond may be reduced drastically (by a factor of 20) if provision is made for spraying the discharge water into the air to increase evaporation. The disadvantages of spray cooling are the cost of the power that is required to operate the sprayers (about 1 per cent of station capacity) and the reduction in the station's efficiency that results from permitting the discharge of water at a higher temperature.

The issues associated with the environmental impacts of electric power generation in general are discussed in detail in Volume 6 of this Report.

Bulk Power Transmission

After electric power has been generated, the next stage of its journey to the ultimate user is the bulk power transmission system, which delivers power from the generating stations to the receiving terminal stations. From the receiving terminal stations, power is carried to area-supply transformer stations, and from there to the familiar local transformers and thence to the users. Ontario Hydro's bulk power transmission system is predominantly at 230 kV. Recently constructed lines operate mainly at 500 kV, and there are a few old ones at 115 kV. The transmission lines that were in operation in the Ontario Hydro system at the end of 1977 are shown in Table 2.2

Table 2.2 Ontario Hydro's Transmission Lines and Circuits, as of December 31, 1977

Line voltage (kV)	Circuit length[a] (km)	Tower-line length (km)
500	1,038	1,038
345	5	5
230[b]	12,779	9,002
115[b]	11,409	8,882
Total length	25,231	18,927

Notes:

a) The need to distinguish between circuit length and tower-line length arises from the fact that some lines have multiple circuits (in the case of Ontario Hydro, almost all of them are double-circuit). Thus, a 100 km double-circuit line segment is counted as 100 tower-line kilometres, but as 200 circuit kilometres.

b) The majority of the 115 kV circuits and some of the 230 kV circuits are actually part of Ontario Hydro's area supply system. The exact lengths under the bulk transmission category were not available.

Source: Ontario Hydro Statistical Yearbook, 1977.

The development of bulk power transmission in Ontario began in 1910 with a 115 kV system between the hydroelectric plants at Niagara Falls and major load centres in the Toronto-Hamilton area. In 1928, 230 kV was introduced, and the transmission system was expanded mainly at this voltage until the mid 1960s when Ontario Hydro installed its first 500 kV transmission line, from Moose River to Toronto.

Until the early 1950s, Ontario Hydro's generating stations were predominantly hydroelectric, many of them located at some distance from the load centres, and thus, long transmission lines were considered inevitable. The introduction of steam-thermal power plants, fuelled first by fossil fuels and then by uranium, changed the situation, because the siting of such plants is much more flexible. Indeed, the coal-fired Hearn and Lakeview plants were built on the outskirts of Toronto. It soon became clear, however, that the flexibility in locating thermal plants to optimize transmission line layouts was constrained by such factors as air pollution of urban areas (especially by coal-fired plants), public concern about the risk of accidents at nuclear plants, the need for great quantities of cooling water, and the realization that extensive economies could be achieved by grouping several large generating units at one site.

These constraints and considerations led Ontario Hydro to build its generating stations close to but outside major load centres on the shores of the Great Lakes. The need for a bulk power transmission grid to interconnect these generating stations with the load centres was accepted because of the resulting improved system reliability and reduced operating costs, as already explained.

The growth in bulk power transmission voltage in Ontario was a result of the growth in power transmission requirements. Although the voltages at which power is generated in large modern generating

units are often lower than 25 kV, transmission voltages are considerably higher (230 kV or 500 kV), in order to limit transmission losses. The power lost in a line as heat is proportional to the square of the current (if the current is doubled, the heat loss is quadrupled). Since the power transmitted is proportional to the product of the voltage and the current, the best way to reduce the loss is to transmit power at low levels of current and correspondingly high voltages.

In the early days of power system development, electricity was generated, transmitted, and used as direct current (DC). DC voltages cannot readily be transformed, i.e., changed from one level to another. Since the use of DC at high voltages was inconvenient, if not impossible, DC generation and transmission was restricted to low voltages, which are extremely uneconomical for long distances or for large amounts of power. Alternating current (AC), due to the nature of the magnetic fields associated with it, can be transformed efficiently to any desired level, and thus can be transmitted at high voltages and used at convenient lower levels. AC generation, transmission, and distribution replaced DC, and most power systems in the world today are AC. The highest AC voltage level used in Canada at present is 735 kV, on Hydro-Québec's system. Voltages in the 345 kV to 765 kV range are called extra-high voltages (EHV). Voltages higher than 765 kV, e.g., 1,000 kV and 1,500 kV, are called ultra-high voltages (UHV). 765 kV is the highest voltage used on commercial installations anywhere in the world today, but in the next decade or so UHV transmission may be installed on some systems.

The choice of bulk power transmission voltage is determined by the amount of power to be transmitted, the distance of transmission, and the configuration of the system. The efficiency and economics of transmission are the criteria for the selection of a particular voltage level. Table 2.3 illustrates the capital costs and the right of way requirements for transmitting 4,000 MW over a distance of 160 km at various transmission voltages. It is clear from Table 2.3 that, for this particular application, 500 kV is an appropriate choice. Because it is Ontario Hydro's policy to locate large thermal stations close to load centres, it has selected 500 kV for the future bulk power transmission network.

Table 2.3 Capital Costs and Right-of-Way Requirements to Transmit 4,000 MW over 160 km

Transmission voltage (kV)	230	500	765
Typical circuit capability (MW)	280	1,920	4,500
Number of circuits	14	2	1
Capital cost (1976 dollars)	200×10^6	60×10^6	70×10^6
Right-of-way width (m)	285	75	93
Land use (hectares)	4,560	1,200	1,488

Sources: Ontario Hydro, "Transmission-Technical", submission to the RCEPP, March 1976, Exhibit 5. Ontario Hydro, "Transmission Planning Processes", submission to the RCEPP, June 1976, Exhibit 22.

The power capability of a transmission line varies with the length of the line and its current-carrying capacity, as well as with the current-carrying capacity of other transmission equipment such as transformers and circuit-breakers. The power capability decreases as the distance increases. The design of a given transmission line is greatly affected by the configuration of the total bulk power system and by the associated stability and security criteria. Both aspects of transmission will be considered in Chapter 4. What is meant by stability and security will be explained briefly here.

All of the generating units (that is, synchronous alternators) on the Ontario Hydro system, and on all of the systems with which it is interconnected, operate in synchronism, rotating at speeds that are in lock-step with the North American standard frequency of 60 cycles per second. It is essential that all the generators stay in lock-step. If generators go out of synchronism, violent swings in generator and transmission loadings occur, which could, quite literally, shake the whole system apart unless the troublesome elements were quickly removed from service. The stability of a system refers to its ability to remain in synchronism despite disturbances.

During normal operation, the power system is subjected continually to minor disturbances caused by a multiplicity of load changes (e.g., when consumers switch power on and off). The response of the power system to these minor disturbances, which is controlled automatically by the individual generator excitation systems, is a measure of its dynamic stability. However, if a major fault (e.g., the loss of a bulk power transmission circuit) occurs near a large generating station, the generators on line react within a fraction of a second, and there are large swings in power flow across the system. The transmission system interconnecting the generators must be of sufficient capacity to accommodate these

changes in power flow. Otherwise, a generator may pull out of lock-step, and unless it is quickly taken out of service the disturbance may spread over the whole interconnected system. The ability of a system to remain stable after a major disturbance is known as transient stability. The security of a system refers to its ability, not only to remain stable after a disturbance, but also to regain an acceptable operating steady state. The two regional reports of the RCEPP on the need for additional bulk power facilities in southwestern and eastern Ontario contain a discussion of the security aspects of transmission planning in Ontario.[1]

Transmission lines are only one of the numerous elements that comprise a bulk power transmission system. Important among the others are power transformers, circuit-breakers, buses, synchronous condensers, static capacitor banks, and shunt reactors. As the name implies, power transformers change transmission voltages from one level to another. They tend to be huge – a typical modern transformer to step the voltage down from 500 kV to 230 kV has a mass of about 300 tonnes. Circuit-breakers are devices that close or open power circuits not only under normal operating conditions but also in an emergency. They differ from ordinary power switches in that they can interrupt fault currents that may be at 16 to 20 times the normal operating levels. Buses are, essentially, large copper or aluminum conductors that are the common connection points for all transmission circuits entering a transformer station. Synchronous condensers, static capacitor banks, and shunt reactors are installed at transformer stations to provide reactive power compensation and thereby facilitate voltage and power factor control across the system.[2] The cost of the transformers and other transmission equipment at the end of 1977 represented about 9 per cent of Ontario Hydro's capital investment, compared with 10 per cent for transmission lines and 61 per cent for generating facilities.

Recently, there has been a revival of interest in high-voltage direct current (HVDC) systems for the transmission of large amounts of power over great distances. HVDC transmission requires, basically, two more steps than HVAC transmission. At the generating end, after the AC-generated power has been transformed to a bulk transmission voltage level, it is converted to DC by rectifiers at the same voltage, and then transmitted as DC. At the receiving end, the high-voltage DC power is converted back to AC by inverters, and then the voltage is stepped down, for distribution.

The main advantages of HVDC transmission are:

- A single-circuit AC line has three phases and, normally, two skywires (located at the top of the towers, skywires protect the line against lightning and carry fault currents), whereas a bipolar DC line has two poles (positive and negative) and, usually, one skywire. The wiring requirements for HVDC are thus smaller and less expensive.
- The smaller number of wires needed for DC overhead lines means that smaller and lighter towers can be used and that the right of way can be narrower.
- DC transmission permits the interconnection of two power systems that may not otherwise be capable of parallel operation. For example, the systems of Ontario Hydro and Hydro-Québec, due to stability considerations, cannot in their present form run in synchronism as one system. To interchange power, one party must isolate some of its generating stations from its system, and then connect those stations to the other system. Due to the same limitation, the Quebec and New Brunswick systems are interconnected by an HVDC link.
- For underwater or underground transmission where cables must be used, the use of AC is quite limited because, at some critical length, the AC cable becomes loaded with reactive power. For a 500 kV AC cable, the critical length is about 25 km. This limitation does not exist with DC cables. DC is particularly useful for underwater transmission over great distances; for example, there is the 32 km 260 kV HVDC underwater cable between Vancouver Island and the mainland.
- There are no stability problems associated with DC transmission.

HVDC transmission has some disadvantages also:

- A main disadvantage of DC transmission is the cost of the conversion equipment (rectifiers and inverters) at the terminals.
- A lack of experience with HVDC and the complexity of the terminal equipment have resulted in reliability problems at some HVDC installations. However, with the introduction of solid-state devices called thyristors, for the rectification and inversion of power, the reliability of HVDC systems is expected to improve.
- Because of the high initial cost of terminal equipment, overhead HVDC transmission is economical only for long-distance, point-to-point, bulk power transmission. These distances are in the order of 650-800 km or more. An example is the Nelson River Project in Manitoba. This project

consists of two bipolar HVDC lines, each 890 km long and operating at ±450 kV. The first line's capacity is 1,620 MW. The second line is operational, but at only half the rated capacity of 1,800 MW; it is expected to be loaded to full capacity by 1981.

Ontario Hydro is studying two applications of HVDC:

- An HVDC interconnection with Hydro-Québec. For the reasons given earlier, an HVAC interconnection is not considered practical for this application. The ultimate capacity of this HVDC tie could be 3,000 MW.
- An HVDC transmission line between Ontario Hydro's East System and its West System. This tie, with a length of 600 to 800 km, may be economical because it would cross largely unpopulated areas and thus would not have any load supply along the way. The tie might have a capacity of 1,000 to 2,000 MW in the late 1980s.

The Distribution of Electric Power

Electric power from the bulk power transmission system (at 230 kV and 500 kV) undergoes a number of voltage transformations before it reaches the ultimate customer. Ontario Hydro classifies them in three categories: area supply, subtransmission, and distribution. The bulk power at 500 kV or 230 kV is transformed to 230 kV or 115 kV at the receiving terminal stations, from which it is fed into the area supply lines (Figure 2.2). These lines, which take power to area-supply transformer stations in or near cities and towns, are mainly overhead, but in large cities such as Toronto they are often placed underground. At the area-supply transformer stations, power is stepped down from 230 kV or 115 kV to 44 kV, 27.6 kV, or 13.8 kV. These stations are also the delivery points for large industrial customers of Ontario Hydro, for example, the petrochemical industries in Sarnia. For other customers, power is fed into the subtransmission lines, which deliver it to distribution stations in or near cities, towns, and villages.

At the distribution stations, power is stepped down further for supplying to individual customers or groups of customers. A number of distribution voltages are in use in Ontario. For distribution to groups of customers, the voltage level is usually 12.48 kV, 8.32 kV, or 4.16 kV. In old residential areas, the distribution lines at these voltages are usually strung on wood or concrete poles routed along the streets. In new residential subdivisions they are often placed underground. Distribution transformers are used along these lines (on poles for overhead lines and on above-ground concrete foundations in metal casings for underground cables), to step the voltage down to serve individual customers. The voltage level is 120/240 V for residential, 120/240 V or 120/208 V for small commercial customers, and 600 V for light industries. The higher of the two voltages available to residential and small commercial customers is for high-power appliances such as stoves, refrigerators, washers, and dryers. The higher voltage permits a more efficient utilization of electric energy by such devices.

In Ontario, most of the generation, bulk power transmission, area supply, and subtransmission facilities are owned and operated by Ontario Hydro. Most major urban centres are served by municipal electricity utilities that buy power from Ontario Hydro and retail it to their customers. However, Ontario Hydro provides power directly to certain industrial customers,such as pulp and paper, petrochemical, and mining companies, and to retail customers in rural areas and communities not served by municipal electricity utilities.

The End Use of Electricity

From the distribution network of an electric power system, electric energy is supplied to hundreds of diverse users. In our day-to-day activities, we use electricity for five basic purposes: heating (resistance heating, induction heating, microwave heating, arc furnaces, and infrared heating), lighting, motors, electrolytic processes, and electronic devices such as television, radios, amplifiers, and computers. The nature and amount of each end use varies from one segment of society to another. In the steel industry, high-power electric motors are used to drive giant rolling mills on a more or less continuous basis. In contrast, small electric motors are used in the home to power appliances such as blenders, washers, and dryers, and these are normally used rather infrequently and for short periods.

Traditionally, the end use of electricity, and of energy in general, is classified in four market sectors – industrial, transport, residential, and commercial (the commercial sector includes all uses that are not included in the other sectors, e.g., street lighting, office buildings, hospitals, and water works). This classification reflects the nature and size of the various end uses of electricity. In Ontario, it also reflects the rate structure to a certain extent.

In Ontario, and in North America as a whole, almost a quarter of the total energy consumed is used in the transport sector. However, most of this energy is in the form of diesel oil, kerosene, and gasoline. The transport sector accounts for an insignificant part of the total electric energy use. In Ontario, for example, the only major user of electricity in this sector is the public transit system of Toronto. For this reason, we will include the electric energy consumed by the transport sector with that used in the commercial sector.

The industrial sector, the largest of the sectors, took more than 40 per cent of the total electric energy consumed in Ontario in 1976 (Table 2.4). The largest single end use in the industrial sector is the electric motor drive, accounting for more than 75 per cent of total industrial consumption. The other industrial uses of electricity are direct heating, electrolytic processes, and lighting. Manufacturing accounted for about 80 per cent of the total industrial electric energy consumption, and mining for about 10 per cent.

Table 2.4 Ontario Electricity Consumption – 1976

End-use sector	Share of total electricity consumption (%)	Share of use within the sector (%)
Industrial		
Direct heat	2.8	6.9
Motor drive	30.6	75.9
Electrolytic processes	2.8	7.0
Lighting	4.1	10.2
Total	40.3	100.0
Commercial		
Space heating	2.1	6.8
Water heating	1.4	4.5
Air conditioning	8.9	28.8
Lighting and other	18.5	59.9
Total	30.9	100.0
Residential		
Space heating	5.8	20.1
Water heating	8.6	29.9
Air conditioning	0.3	1.0
Other appliances	14.1	49.0
Total	28.8	100.0
Ontario total	100.0	–

Source: Royal Commission on Electric Power Planning, "A Race Against Time", Interim Report on Nuclear Power in Ontario, September 1978, p. 20.

The commercial sector was the second largest user of electricity in Ontario in 1976, with a 31 per cent share of the total (Table 2.4). In this sector, electric energy is used almost entirely for heating, cooling, and lighting. This sector was the fastest-growing one (more than 10 per cent annually) in the 1960s and early 1970s. However, in the late 1970s the growth rates declined.

A significant factor contributing to the rapid growth of the commercial sector over the last two decades has been the trend, in office-block construction, towards the use of large areas of glass, making it necessary to install more sophisticated and energy thirstier heating and cooling systems than are required in older buildings. However, engineers and architects have found that in the course of a year, in a properly designed commercial building, the combination of the heat of the sun falling on the structure and the heat generated by the occupants and their equipment, including lighting, can exceed the heat required to maintain a comfortable temperature. Ontario Hydro's head office in Toronto and Gulf Oil of Canada's office in Calgary are examples of such a design. Even during the winter months, the heat losses and the heat gains in a typical Toronto commercial building are approximately the same.

The share of the residential sector in the consumption of electric energy is roughly 29 per cent (Table 2.4). About one-half of the electricity consumed in this sector is used for space heating and water heating and the other half is used for lighting and appliances. The growth in the residential use of electricity in Ontario in the 1960s outstripped the growth in total energy used in this sector. The principal element in this growth was electric space heating, which grew by 15.5 per cent per year, on the average, between 1961 and 1971. This rapid growth in electric space heating was a result of the relatively low price and the convenience of electricity. It was enhanced by Ontario Hydro's promotion campaign encouraging everyone to "live better electrically". The advantages of electric heating are

that it is clean, it requires little maintenance, it responds quickly to the user's changing needs, and its installation cost is relatively low. In the 1970s, however, the cost of centrally generated electricity has risen sharply due to increases in the capital cost of thermal plants and in the prices of coal, oil, natural gas, and uranium. This, coupled with the low annual load factors of electric space heating, has reduced the attractiveness of this method of heating in Ontario.

The Nature of the Demand for Electric Energy

For most North American utilities, the demand for electric power (that is, the electricity load) within a given year varies from hour to hour, from day to day, and from one season to the next. Ontario Hydro's load arises from hundreds of diverse end uses – water-heaters, milking machines, household lights, blenders, chick-brooders, mixers, saws, radios, television sets, furnaces, washers, dryers, refrigerators, stoves, floodlights, streetcars and subways, boring mills, grinders, rolling mills, electrochemical processes, etc. Although the patterns of use of the individual devices are very diverse, their combined use results in total load on the generating system that, while varying over a given period of time, has a relatively orderly pattern.

Hourly, Daily, and Seasonal Variation

For a working day in December, a working day in July, and a weekend in December, the hourly variations of load for Ontario Hydro's total system are as shown in Figure 2.4. For the December Fig. 2.4: p. 18 working day, the load increases from a minimum during the early-morning hours to a secondary peak around noon and then to the daily peak in the early-evening hours. The evening peak on a winter's day is a result of the living habits and employment patterns of the majority of the population – when people come home from work at the end of the day they switch on the lights, turn up the heat, and start cooking supper. For the July working day, the load is more even during the daytime and the daily peak may occur at almost any time between 10:00 a.m. and 6:00 p.m. The absence of an evening peak in the summer is explained to a large extent by the reduced need for lighting and heating.

Figure 2.4 also indicates that the daily peak is more than 20 per cent lower in summer than in winter. This illustrates the seasonal variation of electrical load in Ontario. Ontario Hydro is a winter peaking utility, and the loads are considerably lower in the summer months than in the winter months. The seasonal variation in load is more clearly illustrated in Figure 2.5, which shows the daily peak and Fig. 2.5: p. 19 minimum loads for the Ontario Hydro East System in 1975. Figures 2.4 and 2.5 also show how the load can vary within a week. The loads are generally lower at weekends than on weekdays, primarily because of reduced commercial and industrial activity.

Load Factor

Over a given period, the ratio of the average demand for electric power to the peak demand is called the "load factor". The load factor is calculated by dividing the total demand for electric energy (in kilowatt hours) in a given period by the product of the peak demand (in kilowatts) in the period and the length of the period (in hours). For Ontario Hydro, typical load factors are:

	East System (%)	West System (%)
Winter working day	81-87	90-95
Summer working day	84-88	90-96
Calendar year	64-67	77-80

The higher load factors for the West System reflect that area's greater primary industry loads, such as paper manufacturing and mining, which tend to operate continuously throughout the week. The significantly lower annual load factors (as against daily load factors) reflect the extent of seasonal variation (Figure 2.5). The electrical load is considerably smaller on a summer day than on a winter's day. We will discuss later how the utilities take advantage of this seasonal variation by carrying out the routine maintenance of their generating equipment during the season of low demand (see Figure 2.5).

Load-Duration Curves

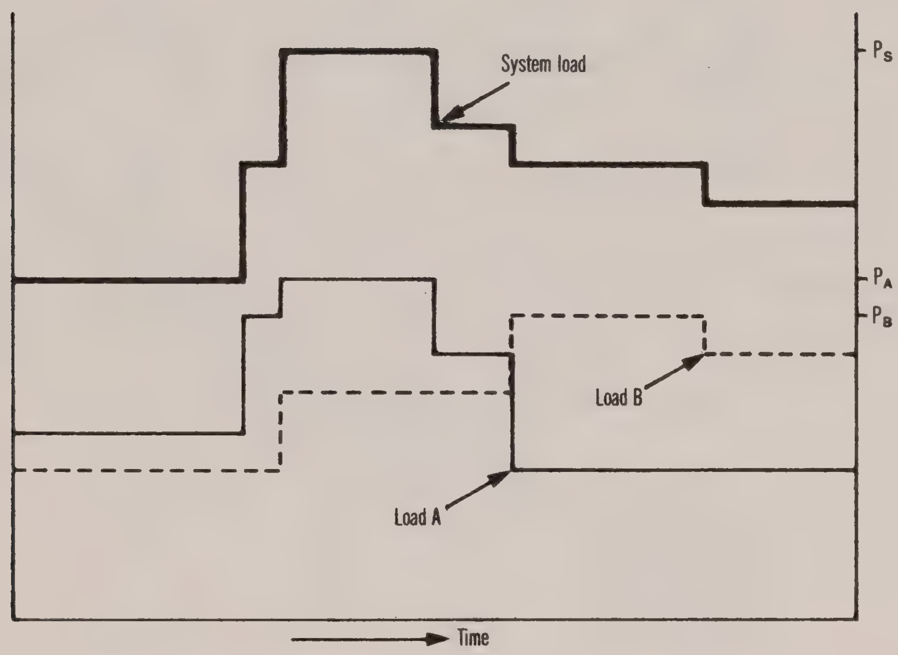
The load shapes shown in Figures 2.4 and 2.5 make it clear that, over a given period, there is a range within which the load varies. The minimum value is called the base load and the maximum value is called the peak load. The base load over a period of a year lasts for all 8,760 hours of the year, whereas the

peak load lasts for less than an hour. Loads that last for less than a year but for more than an hour are termed intermediate loads.[3]

For planning purposes, Ontario Hydro finds it useful to utilize the concept of a "load-duration curve'. The load-duration curve over a given period of time (e.g., a year) is an ordered arrangement of hourly loads, each consisting of the average load over one clock hour, from the highest to the lowest (Figure Fig. 2.6: p. 20 2.6), and it is obtained from the pattern of hourly loads (Figure 2.4) over that period. As Figure 2.6 indicates, Ontario Hydro, for convenience, uses a standardized form of the load-duration curve in which a given level of load is represented as a percentage of the annual peak, and the duration is represented as a percentage of the total number of hours in the year. The "20-minute" peak refers to the 20 minutes during which the total energy demand was the highest, and is the average value of the load over that peak period. The system should, however, be capable of meeting the momentary peak that is higher than the 20-minute peak.

A load-duration curve illustrates the relationship between a load and its duration. It may be seen from Figure 2.6 that in 1977, for 40 per cent of the time (about 3,500 hours), the load in Ontario Hydro's East System was greater than 70 per cent of the annual peak. The concept of a load-duration curve is a useful and important one. The area under an annual load-duration curve is equal to the annual energy demand. From this it also follows that the annual load factor is equal to the average value of the load-duration curve.

Figure 2.1 Illustration of Load Diversity

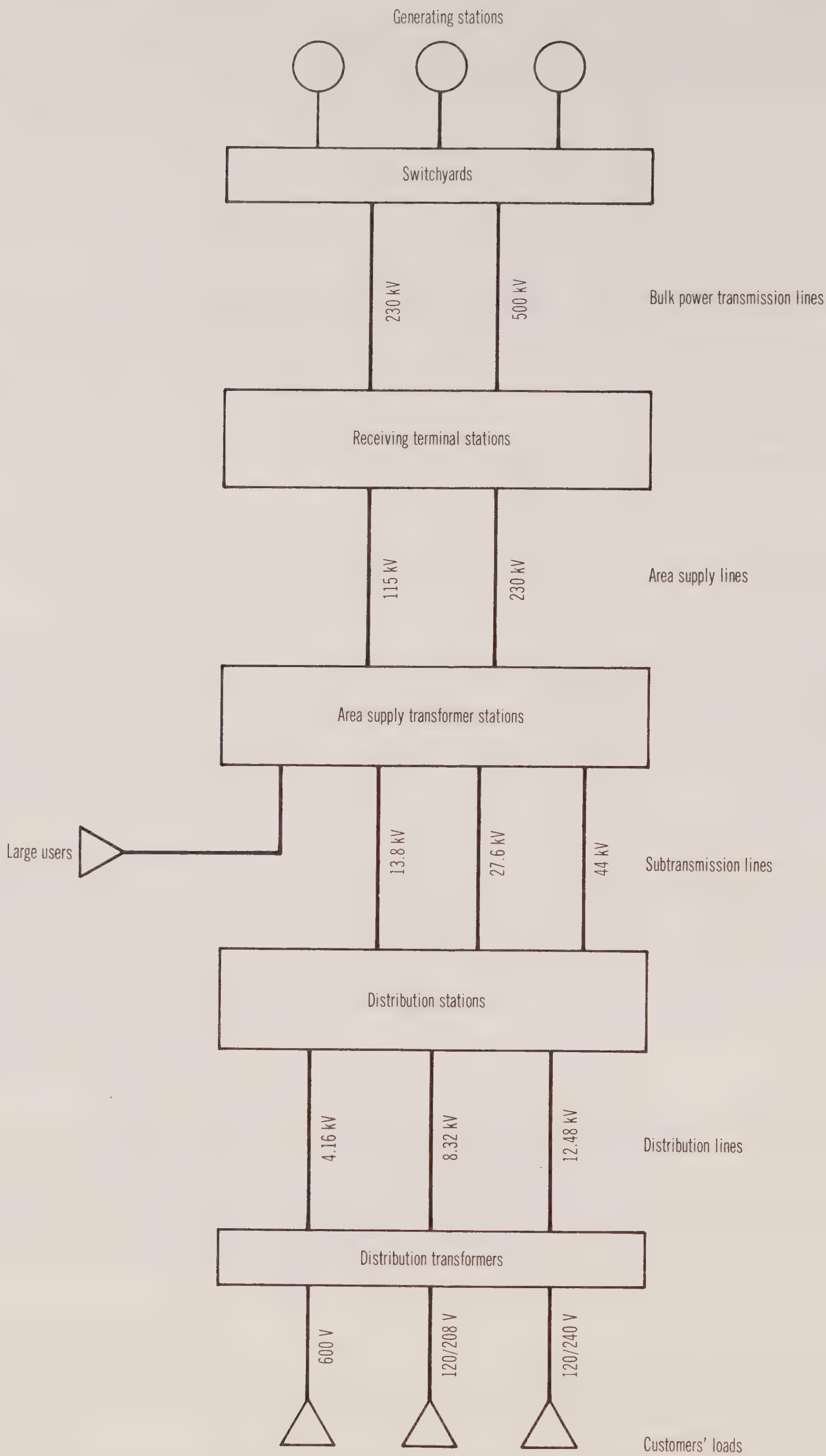


System load = Load A + Load B

$\bar{P}_S < \bar{P}_A + \bar{P}_B$

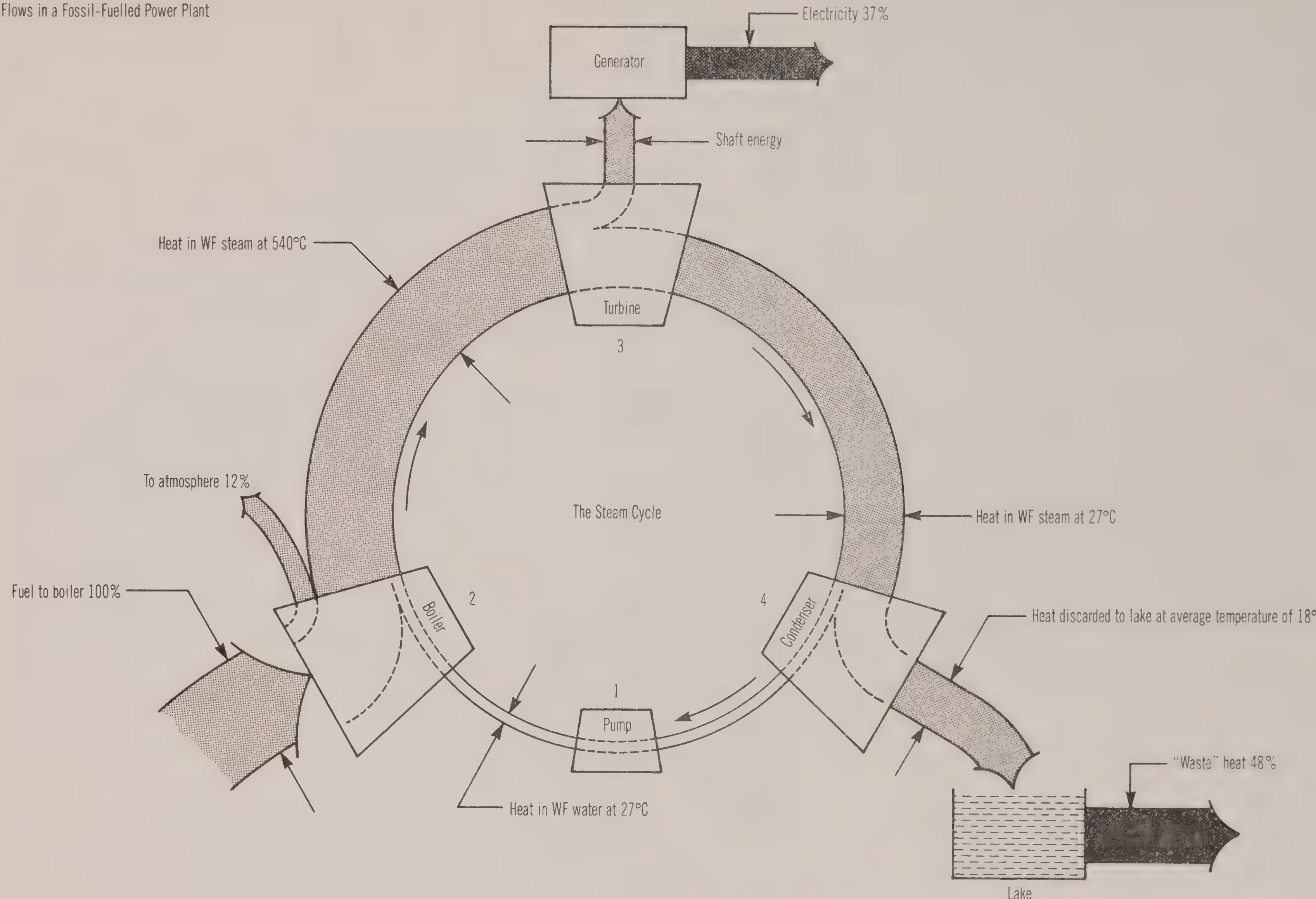
Source: RCEPP.

Figure 2.2 Components of an Electric Power System



Source: RCEPP.

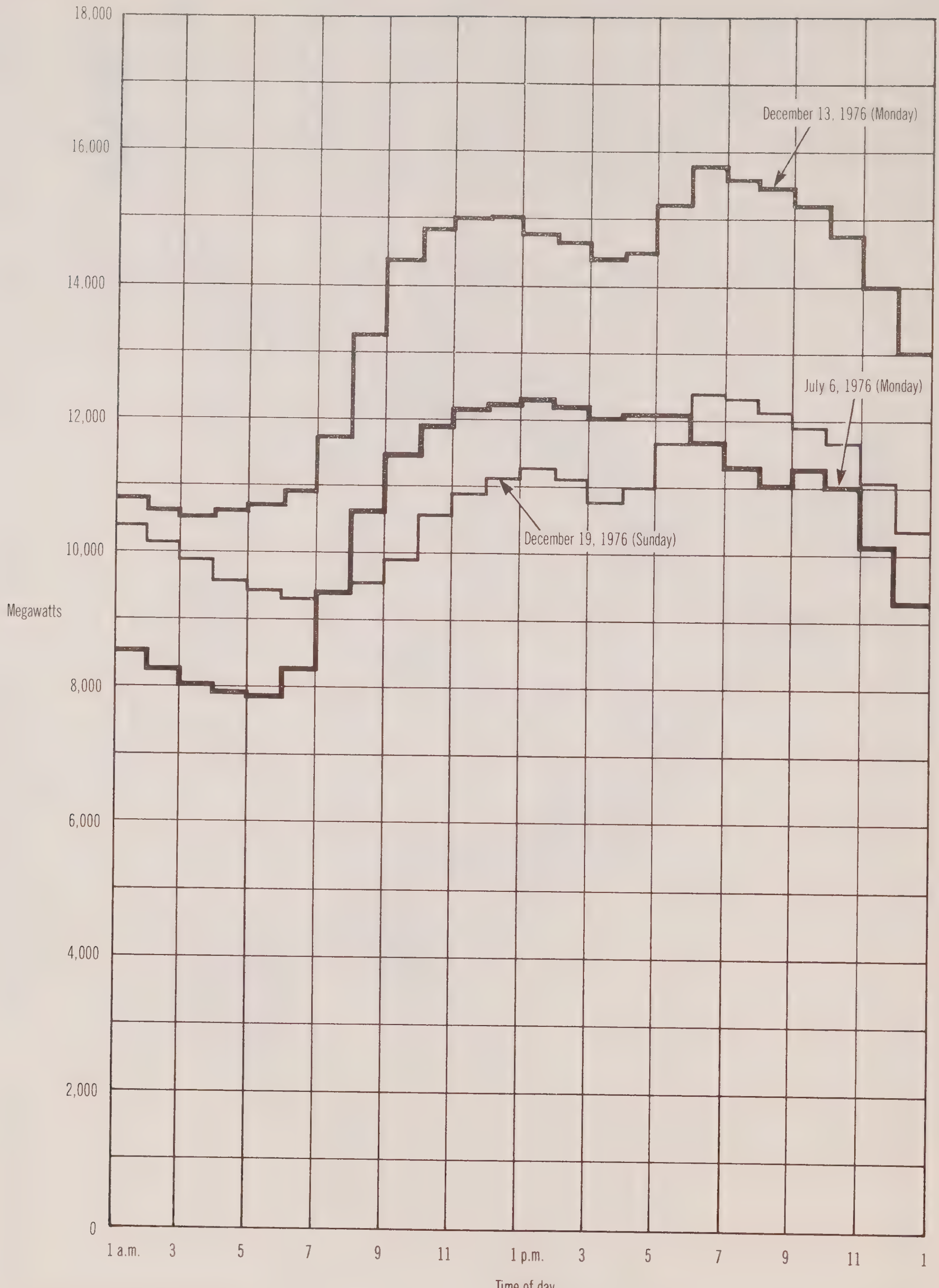
Figure 2.3 Energy Flows in a Fossil-Fuelled Power Plant



Source: "Generation—Technical", Ontario Hydro submission to RCEPP, March 1976, Exhibit 2.

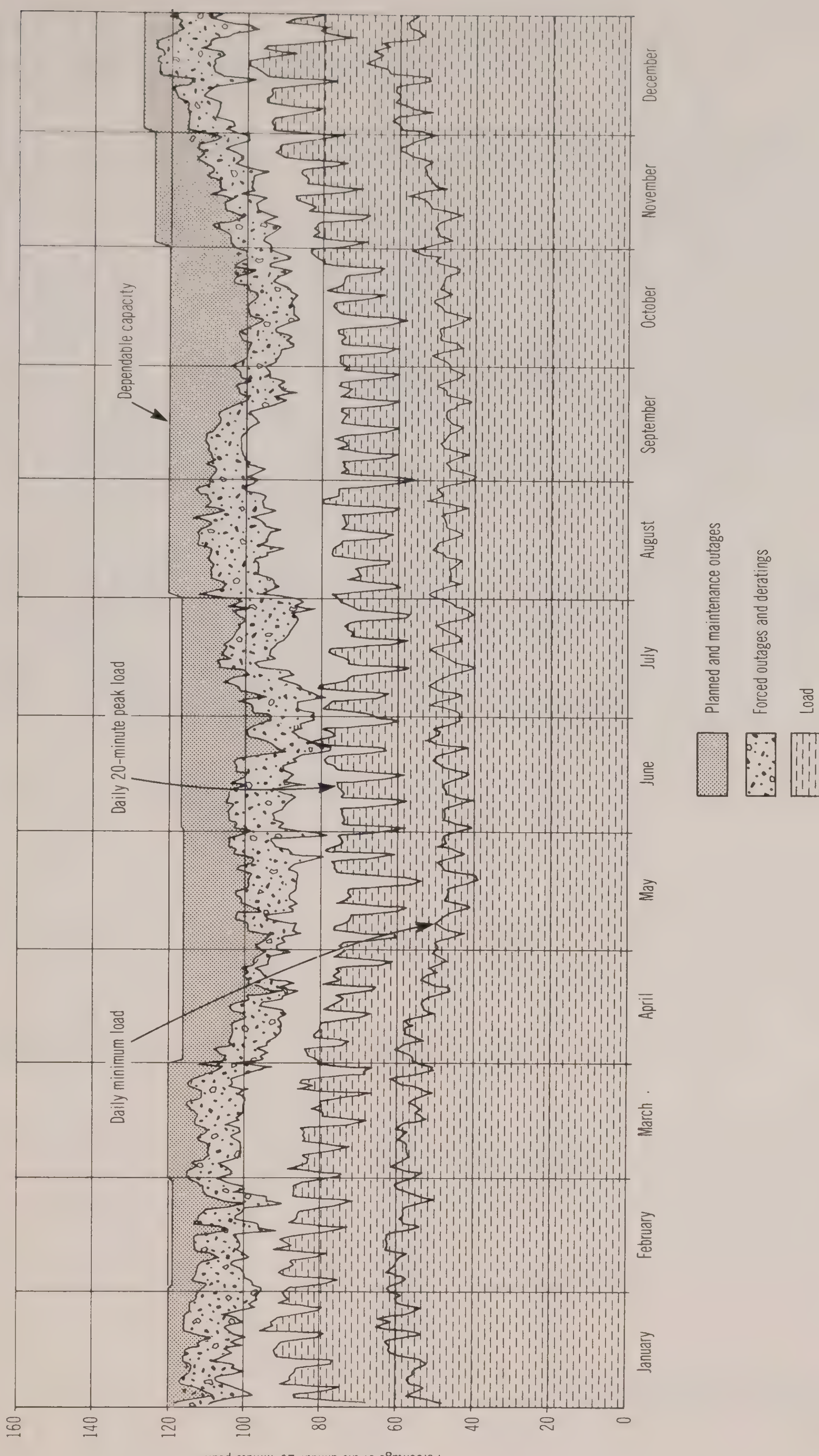
Note: The working fluid (WF) steam and water is moved round and round the cycle by the pump. It is the energy carrier. It picks up energy at the boiler, gives up some by rotating the turbine, discards the rest at the condenser, and is returned by the pump to the boiler. The 3% not accounted for is made up mainly of radiation, generation, exciter losses, and heat bled for building and other heating

Figure 2.4 Ontario Hydro Daily System Load Patterns



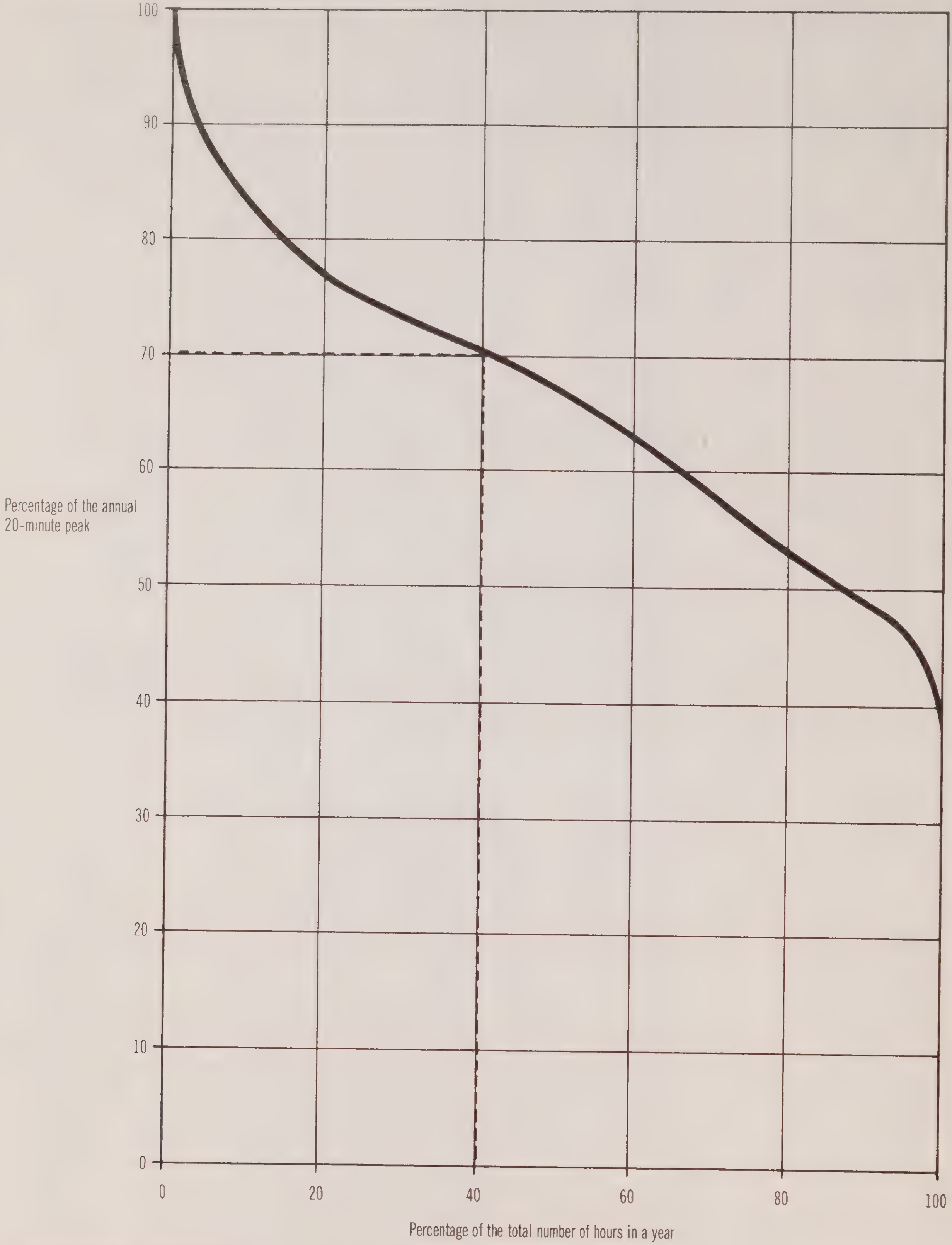
Source: "Electricity Demand", Ontario Hydro submission to RCEPP, April 1977, Exhibit 83.

Figure 2.5 Daily Capacity and Primary Load (Ontario Hydro East System — 1975)



Source: "Reliability", Ontario Hydro submission to RCEPP, May 1976, Exhibit 20.

Figure 2.6 Annual Percentage Duration Curve of Hourly Demands (Ontario Hydro East System — 1977)



Source: "Bulk Power Facilities — Eastern Ontario",
Ontario Hydro submission to RCEPP, December 1978,
Exhibit SE-2.

CHAPTER THREE

Mix of Generating Resources

To be useful, electric energy must, as noted in Chapter 2, be converted from some primary source of energy, such as coal, uranium, or flowing water. In the context of an electricity generating system, "mix" refers to the proportions of the various primary energy sources used in the system. Many factors affect the choice of a generating mix for a given electricity supply system. Some of the important factors are the pattern of demand for electric energy (see Chapter 2), the comparative costs of various generation technologies, technical and operating limitations, the availability of primary fuels, the diversity of the fuel base, and socio-environmental considerations.

Before any discussion of the need for a mix and the factors influencing its selection, the distinction between capacity mix and energy mix should be explained. It is evident from the load-duration curve in Figure 2.6 that about 45 per cent of the annual peak load is base load. The system load factor, which is a measure of the total electric energy requirement, was 65.5 per cent for the Ontario Hydro East System in 1977. Since the base load lasts for the whole year, the amount of energy associated with the base load is approximately (45 divided by 65.5 =) 70 per cent of the total energy requirement. Thus, although the base load component is about 45 per cent of the peak load, the base load energy is 70 per cent of the total energy requirement. What is left makes up 55 per cent of the peak load but only 30 per cent of the total energy requirement.

The same is true of the generating plants. A 2,000 MW nuclear plant supplying the base load will have the same share of the total generating capacity as a 2,000 MW oil-fired plant providing peak load. However, the amount of energy supplied by the nuclear plant will be a considerably larger fraction of the total energy supplied than in the case of the oil-fired plant. Thus, it is important to distinguish between the mix of energy actually being supplied and the mix of generating capacity. Table 3.1 illustrates this distinction by showing the capacity mix and the energy mix of the various electric energy generation resources that were being used in the Ontario Hydro system in 1978.

Table 3.1 Generating Capacity and Energy Mix: Ontario Hydro System – 1978[a]

Resource type	Capacity mix[b] (%)	Energy mix (%)
Hydraulic	28.2	37.4
Nuclear	19.9	30.3
Coal	37.4	28.3
Natural gas	2.6	2.2
Oil	11.9	1.8
Total	100.0	100.0

Notes:
a) Does not include purchases.
b) Based on December Dependable Peak Resources.
Sources: Ontario Hydro Power Resources Report – 790201. Ontario Hydro Annual Report 1978.

The hourly, daily, and seasonal variations in the demand for electricity put an important requirement on the generating system, namely, that it should be able to supply loads lasting from a single moment to a whole year. In the Ontario Hydro system, due to factors of cost, reliability, and operating characteristics, and because the amount of hydraulic capacity is limited, this requirement can best be met by a variety, or mix, of generation types, such as coal, oil, gas, and nuclear thermal generation and hydraulic generation. These and other factors that affect the conventional types of generation are detailed in Appendix B. This chapter will provide a comparative assessment of these factors.

Comparative Costs of Generation Alternatives

To facilitate discussion, the total cost may be divided among capital cost, operations and maintenance (O&M) costs, and energy production cost, or fuel cost. Capital cost is defined as the sum of the direct costs (capital equipment, physical plant, etc.) and the indirect costs (engineering services, construction camps, etc.) that are needed to design, construct, and commission a project, as well as the interest on funds spent during construction up to the actual in-service date. It is expressed as dollars per kilowatt of installed capacity. The O&M costs include the costs of the labour and material required to maintain

and operate a plant, and in the case of nuclear plants also the heavy-water upkeep and any additional security costs. The O&M costs do not depend to any great extent on the amount of energy produced and thus are expressed in terms of dollars per kilowatt per year. The fuel cost reflects the cost of ready fuel, e.g., the cost of fabricated uranium fuel bundles, and is expressed in terms of dollars per kilowatt per hour of electric energy produced. Table 3.2 provides a comparative cost assessment of the generation resources at present being used in Ontario. The actual dollar values are outlined in Appendix B, but to demonstrate the economic suitability of various forms of generation for loads of different durations, a comparative assessment is useful.

Table 3.2 Comparative Costs of Conventional Generation Technologies Used in Ontario

Generation technology	Capital cost	Operating cost
Hydroelectric	site-dependent	very low
Steam thermal		
Nuclear	high	low
Coal	medium	medium
Oil and natural gas	medium	high
Combustion turbine	low	very high

Source: RCEPP.

The capital costs of hydroelectric developments tend to be high, but such plants, once built, are virtually unaffected by inflation, because the "fuel" is free. The operating costs consist mainly of maintenance and water-rental charges, which are relatively small. These cost characteristics make hydraulic power best suited for base-load generation, but the maximum amount of energy that can be generated at any potential site is limited by the size of the available water supply and the difference in elevation, called the "head", through which the water can be made to fall. These factors are determined by the natural features of the site: the pattern of rainfall and runoff, the topography, and the geology.

The pattern of runoff for some rivers, e.g., the Abitibi and the Mattagami, tends to be highly variable from season to season. For such rivers, it is generally desirable to develop sufficient water storage capacity to make it possible to regulate the flow into the turbines so that it corresponds to the variations in the load (the excellent load-following capability of hydraulic units will be discussed later in this chapter). On the other hand, for rivers in which the flow is more or less uniform throughout the year, e.g., the St. Lawrence, such storage may not be desirable, for navigation reasons. Thus, depending on the natural pattern of inflow and other considerations, hydraulic plants may be designed for base-load, intermediate-load, or peak-load operation.

In the case of thermal plants, however, if fuel supplies are assured there are no technical restrictions on their operation at any desired energy output, except for scheduled or forced outages. Thus, cost becomes an important consideration in determining their suitability for a load of given duration. Nuclear plants, being relatively expensive to build and relatively cheap to operate, are being used at present on as continuous a basis as possible, and thus they supply the base load. Coal-fired generation can be used for base, intermediate, and peak loads, depending on the cost. Oil- and natural gas-fired plants, having become very expensive to operate, are used for peaking purposes only, but in emergencies they can be used at higher capacity factors, thus helping to permit flexibility of operation.

Cost Comparison: Nuclear and Coal

Of the generation technologies that are in prospect up to the end of this century, CANDU-nuclear and coal-fired steam-thermal generation are the major realistic options for large-scale generation of electricity in Ontario. The major potential large-scale sites for new hydroelectric development are in remote areas of northern Ontario, on rivers flowing into James Bay. Any decision to develop these sites will have to be based on the cost of the individual stations, the costs of bringing the power to southern Ontario, and the socio-environmental impact. Because different proportions of nuclear and coal-fired generation are possible in a planned expansion, assessment of the relative economics of these two options, for loads of varying duration, is relevant. It is possible to summarize such an assessment in a graphic form using the "life cycle" cost data for individual stations. Figure 3.1 shows an assessment based on the data used in a study carried out for the RCEPP [1] (see Appendix B). The comparison is for a new 4 × 850 MW CANDU station and a new 4 × 750 MW coal-fired station, both coming into service in 1985. The operating life of each station is assumed, for the purpose of calculating discounted cash flow, to be 30 years from the in-service date. The price of coal for this comparison is based on a mix of eastern

U.S. coal and Albertan coal, reaching 50 per cent Albertan by 1995. The fuel cost for nuclear generation includes the irradiated fuel-management cost, which is estimated by the study to be \$19.5/kg of uranium (in 1986 dollars) for interim storage and \$28.5/kg of uranium for geological disposal. The total (\$48/kg of uranium) adds approximately \$1/MW·h to the nuclear fuel cost.

Fig. 3.1: p. 34 The intercept on the vertical axis in Figure 3.1 is the sum of the capital cost and the discounted 30-year O&M cost per kilowatt of capacity installed, for each type of plant. The slope of the straight lines is the discounted 30-year fuel cost in dollars per kilowatt hour. Thus, Figure 3.1 shows that, while the fixed costs (capital and O&M) of a nuclear station are higher by approximately 75 per cent, its fuel cost is only about one-fifth that of the coal station. The nuclear station is therefore cheaper in the long run for annual capacity factors higher than 25 per cent. A sensitivity analysis may be carried out from Figure 3.1 to see what variation in parameters is required for coal and nuclear to be competitive for base-load operations – say, for an annual capacity factor of 75 per cent. Such an analysis shows that a break-even annual capacity factor of 75 per cent is achieved if the nuclear capital cost is increased by 100 per cent (that is, to about three times the coal capital cost), or the uranium price is increased by 300 per cent, or the coal price is decreased by more than 50 per cent compared with the reference-case assumptions. The study made for the Commission also showed that, for coal to be competitive with nuclear for base-load use, the real discount rate would have to be increased from 5.5 per cent per annum in the reference case to about 17 per cent. It is recognized in the study that the cost of geological disposal of spent nuclear fuel is quite uncertain, but the estimated cost is such a small part of the total cost that it has to increase by more than one order of magnitude to offset the advantage of nuclear for base-load generation.

While anything is possible, the variations that are required in a given parameter for a new coal-fired station to be competitive with a new nuclear station for base-load operation are not likely to occur. The study therefore appears to be correct in stating that, in terms of the economic costs of new base-load generation in Ontario, "nuclear generating stations are substantially more attractive than coal-fired generating stations". Similar conclusions were arrived at in a January 1979 study by Ontario Hydro's System Planning Division, comparing the economic costs of a 4 × 750 MW coal-fired station and a 4 × 850 MW CANDU nuclear station.[2] The break-even, lifetime, annual capacity factor calculated in the study is 35 per cent when a new nuclear station is compared with a new coal station fired with U.S. coal, and 25 per cent when such a station is compared with a new coal station fired with western Canadian coal.

While studies comparing the cost of various types of generating stations indicate the economic suitability of a station for a given capacity factor, they do not provide an adequate basis for decisions, in a changing planning environment, about the mix and in-service dates of new stations to be added. The capacity factor of a plant changes from year to year and may decline over the plant's life. As new and more efficient technologies are deployed, the old plants are pushed up in the loading order and may be operated at considerably lower capacity factors.[3] This may also happen as a result of an anticipated or unanticipated decline in load forecast. The in-service dates of the new generating facilities is usually determined by system reliability considerations and sometimes also by the economics of substituting a new and more efficient station for the old and expensive one. Also, the cost analysis of single stations does not take into account the impact of various rates of system expansion on the "front end" of the life cycle of a plant, e.g., the capital markets, heavy-water plants, uranium- and coal-mining infrastructures, and coal transportation systems. The economic issues associated with the various generation technologies in Ontario are discussed in greater detail in Volume 5 of this Report.

The Reliability and Performance of Various Technologies

Of all the types of generating units that are used in Ontario, the hydraulic is the most reliable, with a forced outage rate of 0.5 per cent and a capability factor of 95.5 per cent.[4] Ontario Hydro estimates show that the reliability of various steam-thermal generation technologies (nuclear, coal, oil, and gas) is comparable, with capability factors in the 75-80 per cent range. Gas turbine units are the least reliable, mainly because of their high forced outage rates (about 15 per cent). The overall capability of gas turbines is estimated to be about 76 per cent.

When an operating unit goes out of service because of a forced outage, it must be replaced by another unit that will continue to supply the load. The system must have capacity in excess of the peak demand on any day to meet such contingencies. This capacity is called reserve capacity. When expressed as a percentage of the peak load, it is referred to as "reserve margin". The planned maintenance of generating units in the Ontario Hydro system at present takes advantage of seasonal load variations and

does not require additional capacity (see Figure 2.5 in Chapter 2). Maintenance is carried out mainly between March and October when the demand is relatively low. Ontario Hydro's system requires a reserve margin of approximately 25 per cent over the annual peak load. However, due to a sharp decline in the loads from the levels forecast in the early 1970s, the present system has considerable excess capacity. The installed reserve at the time of the winter peak in January 1979 was 43 per cent, representing an 18 per cent surplus. Ontario Hydro is trying to sell some of this excess to U.S. utilities. This issue will be discussed in detail in Chapter 5.

The unreliability of a plant affects the generating mix through the reserve requirements and thus through the additional cost penalties associated with the plant. The economic cost comparisons given earlier did not take into account the cost penalties of the relative unreliability of the generating units. The cost of this unreliability is illustrated by Figure 3.2. It shows the capital cost and the 30-year discounted O&M cost per kilowatt of the nominal capacity as well as of the load-meeting capability of nuclear and coal-fired units coming into service in 1985, as a function of unit size. The load-meeting capability refers to the load a unit could supply with a specified level of reliability, whereas the nominal capacity is the nameplate rating of the unit. The difference between the cost per kilowatt of load-meeting capability and the cost per kilowatt of nominal capacity is a measure of the cost of unreliability, which is approximately 15 per cent of the cost per kilowatt of nominal capacity for the 500 MW CANDU and coal-fired units. A higher percentage cost penalty is associated with bigger units due to their higher forced outage rates and the fact that, for the same size of system, the larger the unit size, the higher the reserve requirement for a given level of reliability. For the same reason, the load-meeting capability of a unit is a function both of its forced outage rate and of the size and characteristics of the system with which it is associated. Fig. 3.2: p. 34

The information presented in Figure 3.2 is based on studies made by Ontario Hydro in 1975 on the assumption of a much bigger future system than is being forecast now. To determine the exact effect of a lower system growth forecast on the load-meeting capability would require a detailed computer study. Qualitatively, we can say that a smaller system will have a greater impact on the bigger units as far as a reduction in the load-meeting capability or an increase in the unreliability cost penalty is concerned.

The effect of the unreliability of plants on the utilization of generating capacity to supply load is illustrated by Figure 3.3. This figure is based on Ontario Hydro's generation programme proposed for 1995 in long-range forecast LRF 48 and on Hydro's 1976 load forecast. Although Figure 3.3 is based on old information and is representative of only a given future year, its use here is quite appropriate. The capacity distribution depends on the load-duration curve and on the characteristics of the system's generating units (capability factor, size, fuel cost, and maintenance schedule). However, as long as the mix of stations in the system is more or less unchanged, the shape of capacity distribution will probably not be significantly different. Fig. 3.3: p. 35

The estimated distribution of generating capacity (also known as the plant-duration curve) is related to the principle of "merit order loading" to minimize the expected operating costs. It reflects the effects of forced and scheduled outages and deratings of generating units, which prevent them from operating without interruptions while supplying the load. Because of these outages and deratings, the units at the lower end of the loading order (that is, those supplying the base load) are limited to a capacity factor of less than 100 per cent. To make up for this deficiency in supply to the base load, the units that are higher in the loading order must generate correspondingly more energy. The areas under the plant-duration and load-duration curves (see Figure 3.3), therefore, are virtually equal. Also, since the peak system capacity is more than the peak load (the difference being the reserve capacity), the system capacity factor, which is a measure of overall capacity utilization, is less than the system load factor. For example, if the system load factor is 70 per cent and peak capacity is 25 per cent more than peak load, the system capacity factor is 56 per cent. Note that, in a hypothetical system in which the generating units are available all the time, the plant-duration and load-duration curves would be identical and the reserve requirements would be zero.

The availability, and thus the reliability, of Ontario Hydro's large thermal generating units is an important factor affecting the reliability of any planned generation programme. The Sierra Club of Ontario, in its submission to the Commission in September 1978, expressed concern about the decreasing availability of Ontario Hydro's thermal units and about its forecast of availability of future large units:

> Clearly there has been an alarming decline in the availability of thermal generating units. The

answer is not more spare capacity but identification of the causes of this alarming trend and return to 1970 levels of availability. The Club suspects that the rapid scale-up of plants has been a contributing factor, i.e., larger units, immature designs, and failures in quality control.

With 24 per cent of its thermal units unavailable in 1975, including designs widely used and proven, [Ontario] Hydro's projection of 17 per cent unavailable (12 per cent forced plus 5 per cent maintenance) on mammoth 1,250 MW units must be viewed with great skepticism.[5]

"Alarming decline in the availability" refers to the second column of Table 3.3, which shows the average incapability of thermal units as a percentage of the primary peak demand. The Sierra Club's interpretation of these numbers appears to be misleading. An increase in the average incapability, as a percentage of peak demand, would be expected because of a sharp penetration of the system by thermal units, and is thus a result of the changing system mix. As the table shows, thermal capacity increased from 4,985 MW in 1970 to 10,577 MW in 1975. A relevant measure of the unavailability of the thermal capacity is given by its incapability, expressed in terms of the total thermal capacity and not in terms of peak demand. This is shown in the last column of Table 3.3. It should be pointed out that many of Ontario Hydro's 500 MW-unit thermal stations were put into service between 1970 and 1975 (Pickering 1-4, Lambton 2-4, and Nanticoke 1-5). Thus, the unavailability of the thermal capacity during these years is representative of the incapability of these units during their early years of service, which is forecast by Ontario Hydro to be in the order of 30 per cent and not 17 per cent as mentioned by the Sierra Club. Ontario Hydro's incapability projections include forced and maintenance outage rates as well as a planned outage rate, which is about 10 per cent (see Chapter 4).

Table 3.3 Total Incapability of Ontario Hydro's Steam-Thermal Capacity (1970-75)

Year	Average incapability as a percentage of primary peak demand[a]	Primary peak demand (MW)	Average incapability (MW)	Average thermal dependable capacity (MW)	Average incapability as a percentage of thermal capacity
1970	11	11,289	1,242	4,985	25
1971	16	11,534	1,845	6,395	29
1972	17	12,739	2,165	7,503	29
1973	18	13,606	2,400	8,742	27
1974	22	13,538	2,978	10,171	29
1975	24	14,513	3,483	10,577	33

Note a) Although these data are obtained from page 21 of Ontario Hydro's submission to the RCEPP entitled "Reliability", the incapability for 1973 is changed from 21 per cent to 18 per cent. The average incapability corresponding to 21 per cent of primary peak is 2,860 MW, which appears to be very high when compared with Chart 14D of Appendix 10-E of this submission, which shows the variation over time of the total incapability of Ontario Hydro's thermal capacity in 1973. From this plot, the average incapability appears to be in the order of 2,400 MW, which is approximately 18 per cent of the primary peak demand.

The question of availability is even more significant for the CANDU nuclear units, which are highly capital-intensive and suitable for base-load operation because of their low fuelling costs. Because of the relatively few CANDU reactor years of operation, it is difficult to make a statistically meaningful comparison between their actual availability and their forecast availability. Our analysis is based on the experience (approximately 30 reactor years) with the 4 × 500 MW Pickering A station, whose first unit was in service in 1971. Table 3.4 shows the annual capacity factors (ACFs) of the four units in
Fig. 3.4: p. 36
various years of service. The yearly averages are plotted in Figure 3.4. Also shown in Figure 3.4 is the 1975 Ontario Hydro forecast of capability for use in system planning studies (see Table B.1 in Appendix B). It may be seen that the capability in the first four years of service has been less than expected, whereas in the later years it is better than expected. In terms of the lifetime average capability, both Unit 1 and Unit 2 have done better than Ontario Hydro's forecast average of 77.7 per cent for an eight-year-old unit and 77.4 per cent for a seven-year-old unit. Unit 3's record is not near the expectation, whereas Unit 4's capability is marginally below the forecast average of 76.9 per cent for a six-year-old unit.

On the basis of limited experience with the Pickering A station, it may be concluded that the CANDU reactors should be able to maintain base-load capacity factors. This conclusion is partly based on the clear positive trend in the capability factors with the years of operating experience depicted in Figure 3.4. As far as the availability of the larger CANDU units (for example, the 850 MW Bruce and Darlington units) is concerned, no meaningful analysis is possible because of insufficient operating experience.[6] It should be pointed out that Ontario Hydro's forecast predicts a lower capability for the larger units (77.4 per cent for the 850 MW units, compared with 80.1 per cent for the 500 MW units). An analysis of the operating experience with the light-water reactors (LWRs) in the U.S. indicates "a

Table 3.4 Pickering A Generating Station – Annual Capacity Factors

Year of service	1	2	3	4	5	6	7	8	Lifetime unit average
Unit 1	80	45	92.5	72	80	92.8	85.6	95.1	80.4
Unit 2	50	69	88.4	86	93.2	91.0	84.3	–	80.3
Unit 3	30	85.1	42.7	57.5	93.9	95.6	82.2	–	69.6
Unit 4	90.1	93.9	23.8	68.4	90.8	89.6	–	–	76.1
Yearly average	59.4	73.3	61.9	71.0	89.5	92.3	84.0	95.1	–

Notes:

1) Unit capacity factors and the yearly average for the first year of service are based on operation for only part of the year.

2) The significantly low capacity factors of unit 1 in its second year of service and of units 2 and 3 in their first year of service are in part due to a 1972 strike. This is not attributable to unit design and thus to the unit's capability.

Source: Ontario Hydro, "Reliability", submission to RCEPP, May 1976, Exhibit 20; and other Ontario Hydro information.

distinctive trend in the availability as a function of plant [unit] size".[7] The U.S. data for the pressurized light-water reactor (PWR) category indicate average availabilities of 79 per cent and 72 per cent for the 500 MW and 850 MW units, respectively.

The choice of the optimum unit size on economic grounds is quite sensitive to the rate at which the availability changes with the size. At present, no universally acceptable measures of this rate are available.

In its *Interim Report on Nuclear Power in Ontario*, the RCEPP concluded that "the 1,250 MW CANDU reactors should not be part of Ontario Hydro's system expansion programme before the turn of the century". This conclusion is further underlined by the declining load forecasts by Ontario Hydro, and by the uncertainty about the capability of these units. Concomitantly, it is noted that Ontario Hydro decided in 1979 to stop all work on the 1,250 MW unit.[8]

The Operating Characteristics of Various Technologies

Operating characteristics are an important technical consideration in any assessment of generating mix. The operating characteristics of a generating unit refer primarily to its shut-down and start-up characteristics, its ability to operate at reduced loadings, and its load-following capability, that is, its ability to change its output continuously in response to the changing load.

Hydroelectric units have the best operating characteristics. Each unit can be adapted for any duration of load. Cost considerations and natural features generally determine the type of load for which a hydraulic site is developed.

CANDU nuclear units of current design, because of their high capital and low operating costs, are best suited for relatively continuous operation, that is, for supplying base loads. Ontario Hydro's evidence to the RCEPP indicated that these units can be operated at lower capacity factors by reducing their output overnight by up to 50 per cent and by weekend shut-downs. However, CANDU units have not been especially designed for load-following. The nuclear plants currently committed by Ontario Hydro (up to and including the Darlington Generating Station) are expected to operate only at base-load capacity factors until the end of the century. This situation may change if the load forecasts drop further and the committed nuclear programme is not postponed.

Currently, fossil-steam units are used in Ontario Hydro's system to supply base load as well as intermediate and peak loads, and reserve. The fossil-steam units being considered by Ontario Hydro in its long-range generation plans are best suited, from an operational viewpoint, for the base and intermediate loads, but can also provide peak loads and reserve.

Although gas-turbine units have fast start-up and shut-down characteristics, frequent starts and shut-downs tend to increase their maintenance cost. For the Ontario Hydro system, on the basis of current prices, they are economical for peaking and reserve duty, although they could be operated at higher capacity factors if the need arose and fuel was available.

The Spectrum of Conventional Technologies

It is possible to combine the factors of cost, reliability, and operating characteristics to determine the efficient operating range of each of the electric power technologies. Figure 3.5 illustrates this range in a general way for the conventional generation alternatives in Ontario, including purchased power and storage. As the figure shows, all generation technologies are limited to annual capacity factors of less Fig. 3.5: p. 36

than 100 per cent due to the reliability constraints (forced and scheduled outages). However, this may not apply to the power purchased under a contract from another system. The seller of such power may be bound by the contract to deliver power at a 100 per cent capacity factor. The seller can satisfy this requirement by providing sufficient reserve capacity in his system.

Fuel Requirements and Supply

Ontario Hydro's current contract with Petrosar Ltd. to supply 7.3 million barrels of low-sulphur residual oil per year to 1992 is adequate for the 1,116 MW Lennox Generating Station operating at an annual capacity factor of 50 per cent. (The actual installed capacity of the four-unit Lennox station is 2,232 MW, but two units were taken out of service early in 1979 due to less-than-expected loads.) In its long-range forecast LRF 48A, Hydro indicated that it planned to build one more oil-fired station, at Wesleyville, with a capacity of 2,164 MW, but the planned size was cut in half in view of the lower 1978 load forecast. In February 1979, with a further drop in expected load growth, Hydro announced that it would "mothball" the Wesleyville Generating Station, to reduce excess capacity. All components for that station will be delivered and stored on site until the early 1990s. Of an estimated total cost of $660 million, about $380 million has been committed. Hydro is also planning to consider the advantages of converting the two Wesleyville units to coal, or a combination of coal and oil, before the station is eventually completed. As a result of the cutbacks, Hydro hopes to reduce by one-half the residual oil contract amount of 7.3 million barrels a year over the period ending in 1992. Hydro is not planning any other oil-fired steam-thermal stations.

The future prospects of natural gas supplies for the Hearn Generating Station are good. Its four gas-fired 100 MW units have been taken out of service, in addition to the two Lennox units, due to reduced expectations of future loads. These six units could be brought back into service on short notice. The remaining four 200 MW units at Hearn are fired with natural gas in summer only. Hearn's requirements are estimated at 10 billion cubic feet per year to 1988 and 5 billion cubic feet per year thereafter. These are adequate for Hearn in its role as a peaking or reserve station. In view of the relatively small requirements for oil and gas for the Ontario Hydro facilities, their supply in the future is not a major concern.

The oil- and gas-fired units in Ontario are economical at current prices only for peaking and reserve. Their future use for these purposes may be considerably reduced by the following factors. Ontario Hydro's load forecasts have declined from an average annual growth rate to the year 2000 of about 7 per cent in 1975 to one of about 4.5 per cent in 1979. If the load were to grow at 4.5 per cent, the existing capacity of peaking- and intermediate-load hydraulic generation of about 3,000 MW would provide a significantly larger share of the peaking needs. Moreover, Hydro plans to develop as much as 2,000 MW of new hydraulic capacity at 17 sites, with a total average annual output of 523 MW, equivalent to an annual capacity factor of 26 per cent. This new capacity will supplement Ontario Hydro's peaking resources. The total cost of the development is estimated at $1.4 billion (in 1977 dollars). Ontario Hydro also announced in July 1978 its intention to pursue a load-management programme aimed primarily at flattening the peak on the thermal generating resources, that is, the part of the peak load that is not supplied by hydraulic generation. The load-management target for 1985 is 500 MW, rising to 1,300 MW in 1992 and to about 2,000 MW by the end of the century.

In Ontario Hydro's system, the coal-fired stations constitute about 37 per cent of the total capacity, and they generated 28 per cent of the total electric energy in 1978. They make up a significant proportion of the base-load capacity, at present. Because of the economic advantage of nuclear stations for base load, all generating facilities being built for the 1980s are nuclear (Pickering B, Bruce B, and Darlington), except for a 300 MW extension to the Thunder Bay station and the 400 MW Atikokan station in the West System. With the increasing role of nuclear in supplying base-load energy, the demand for coal is projected to grow modestly from the 1978 level of 9 million tonnes to about 12 million tonnes per year by the end of the century, on the basis of Hydro's 1979 load forecast. Until the late 1980s, Hydro's problem will be not securing supplies of coal but rather reducing the considerable oversupply (see Figure 7.4 in Chapter 7).

Until recently, Ontario Hydro purchased all of its coal from markets in the eastern U.S. Hydro believes that the reliability of supply from existing U.S. sources is good, but that various factors, including the ability of U.S. mines to satisfy both the increasing domestic requirements and exports, could affect the

future supply to Ontario. This factor may have particular significance in the light of a U.S. administration proposal requiring the U.S. electricity utilities to cut their oil consumption in half by 1990 by switching their boilers to coal.

To lessen somewhat its dependence on U.S. coal, Ontario Hydro has contracted for about 2.5 million tonnes of bituminous coal per year from Alberta and British Columbia and about 0.9 million tonnes of lignite per year from Saskatchewan. The transportation system for this supply consists of unit-train movement to Thunder Bay and a terminal at Thunder Bay to transfer coal from trains to lake vessels for shipment to the Nanticoke Generating Station in southern Ontario. Lignite will be unloaded at Thunder Bay and transferred by conveyor belts to the generating station on nearby Mission Island. The bituminous coal will be blended at Nanticoke with U.S. coal (a 50-50 mixture) prior to use there. Movement of the bituminous coal by the integrated transportation system began in 1978 and about 0.5 million tonnes were delivered to Thunder Bay by the end of 1978. Deliveries are expected to reach the full contracted amount in 1980. First shipments of the lignite are also expected in 1980. The contracts for western Canadian coal expire in 1993.

Preliminary estimates of the capital investment required for the new system are in excess of $422 million. Ontario Hydro's share is approximately $79 million, to cover manufacturing of the railroad equipment and construction of the Nanticoke blending terminal. Other costs, being contributed by the companies involved, are $133 million in mine development, $60 million for the Thunder Bay terminal, $90 million towards the improvement of railroad facilities, and approximately $60 million for shipbuilding.

Each unit-train trip will carry about 9,000 tonnes of coal (100 gondola cars with a capacity of 90 tonnes of coal each). Thus, about five round trips per week will be necessary for the bituminous coal and two round trips per week for the lignite. In order to provide upward flexibility, the design of the Thunder Bay terminal is such that its initial capacity of 2.7 million tonnes of coal per year could be doubled to 5.4 million tonnes. Transport capacity could be increased by deploying more unit-trains and lake carriers.

Western Canadian coal has both advantages and disadvantages over coal from the eastern U.S. The disadvantages lie primarily in its quality. Bituminous thermal coals in western Canada have lower heat content (11,000 BTU/lb., compared with 13,000 BTU/lb. for U.S. coal), considerably higher ash content, and sometimes a lower volatile content, which affects combustion stability.[9] Saskatchewan lignite, with only 7,000 BTU/lb., has a very high moisture content – as much as 34 per cent of total weight, compared with 6 per cent in bituminous coal. These factors and the increased transportation and handling costs make western Canadian coal 40-50 per cent more expensive than current supplies of U.S. coal. From the viewpoint of quality, the advantage of western Canadian coal lies in its low sulphur content (0.5 per cent compared with 2.5 per cent for the U.S. bituminous) and this is an asset in terms of air quality and environmental pollution. An increased reliance on Canadian sources will increase the security of supply to Ontario Hydro and have a positive impact on Canada's balance of payments. The investment in a Canadian venture will also provide a direct stimulus to the Canadian economy by creating jobs, and this will mean cash flows into the provincial economies.

Ontario Hydro's existing CANDU nuclear capacity is 5,248 MW. Another 8,612 MW (Pickering B, Bruce B, and Darlington) is under construction or committed and is scheduled to be in service by 1990, increasing the total nuclear capacity to 13,860 MW. At an annual capacity of 80 per cent, the 30-year uranium requirement of this capacity is about 58,000 tonnes. In February 1978, Ontario Hydro received the provincial government's approval to enter into uranium supply contracts with Denison Mines Limited and Preston Mines Limited. These contracts call for the delivery of 76,200 tonnes of uranium beginning in 1980 and continuing through the year 2020 – 48,500 tonnes from Denison over the period 1980-2011 and 27,700 tonnes from Preston over the period 1984-2020. Ontario Hydro has other contracts for about 5,000 tonnes of uranium. The excess contracted supply of about 23,000 tonnes is adequate for the 30-year requirement of 5,400 MW of nuclear capacity beyond the currently committed programme. Table 3.5 gives the latest estimates by Energy, Mines and Resources Canada of the uranium reserves in Canada. Ontario's share of the total of the measured, indicated, and inferred categories is about 68 per cent, that is, about 365,000 tonnes, and of the prognosticated category it is 42 per cent, that is, about 180,000 tonnes. Although Ontario's share for each of the measured, indicated, and inferred categories is not available for the latest estimates, it was 60 per cent, 70 per cent, and 74 per cent, respectively, in the 1977 assessment of uranium reserves. The annual supply-and-demand projections of uranium for Ontario Hydro's expansion programme, corresponding to its 1979 load

forecast as well as to a lower load forecast of 3 per cent average annual growth to the year 2000, are discussed in Chapter 7.

Table 3.5 1978 Estimates of Canada's Uranium Resources (thousands of tonnes of uranium)

	Reasonably assured		Estimated additional	
	Measured	Indicated	Inferred	Prognosticated
Up to $125/kgU	76	139	223	147
$125 to $175/kgU	4	16	79	279
Total	80	155	302	426

Source: "1978 Assessment of Canada's Uranium Supply and Demand", Energy, Mines and Resources Canada. Report EP79-3, June 1979.

Heavy-Water Supply and Demand

Ontario Hydro has three heavy-water plants, operating or under construction – BHWP-A, BHWP-B, and BHWP-D – all at the Bruce nuclear complex (see Appendix B). BHWP-A is operating and BHWP-B is expected to be commissioned by 1980. Only half of BHWP-D is being constructed, and no decision has yet been made on commissioning.

Fig. 3.6: p. 37

The supply-and-demand projections for heavy water are shown in Figure 3.6. The supply projections are based on the operation of BHWP-A and BHWP-B only. Both supply and demand are cumulative, and not annual, quantities. The demand is made up of the central inventory for new reactors, and make-up for losses during operation. As may be seen from Figure 3.6, a surplus in heavy water will develop during the 1980s under Ontario Hydro's committed programme. This surplus will be about 4,000 tonnes of heavy water by 1990, assuming the dependable supply, and 6,000 tonnes, assuming the probable supply. If the expansion of the nuclear capacity in the 1990s continues according to Hydro's 1979 plan (11,450 MW of additional nuclear capacity), the demand will keep up with the dependable supply. The surplus with respect to the dependable supply will stay at 4,000 tonnes, but with respect to probable supply it will increase to 8,000 tonnes by 2000. A tonne of heavy water provides sufficient central inventory for 1 MW of new CANDU capacity. Another way to interpret the surplus is to say that the heavy-water supply capability would permit advancing the whole nuclear programme by up to 3.5 years if required. The figure also shows the heavy-water demand if no expansion of nuclear capacity beyond Darlington takes place, for example, under a 3 per cent load-growth scenario. The surplus in the year 2000, under these assumptions, would be about 15,000 tonnes on the basis of dependable supply.

The above analysis shows that the committed heavy-water production capability is more than sufficient to supply the requirements to the year 2000. It may be concluded that a provision at this time, or in the near future, for the expansion of the heavy-water capability is not needed. Indeed, with BHWP-D, the supply surpluses will increase.

Lead Time

The time required to bring a new generating facility into commercial service, called the lead time, has become a matter of concern to modern power-system planners. In Ontario, the total lead time must allow for four major steps. The first step is the identification of a site for the new station and completion of the necessary procedures, including public participation, for the purchase of the site. The second step is a detailed geological investigation, an environmental and community impact assessment, and the necessary preliminary engineering work so that approval for the project may be sought. If a project is approved, the third step, the preparation of the site, is taken; this includes grading, topsoil removal, and subsoil preparation. This is followed by the last step, which is the detailed design and on-site construction of the facility. The typical durations of each of these four steps for various types of thermal electric generating stations in Ontario are shown in Table 3.6. The lead time for hydraulic stations varies, depending on the site, from eight to 15 years,

The issue of lead time has become extremely significant because of the increasing uncertainty associated with the forecasting of loads. Lead-time constraints may, themselves, eliminate from consideration facilities that cannot be put into service by the time they will be required. To make the planning process responsive to the changing predictions of future loads, it is necessary to reduce lead times as much as possible. Ontario Hydro informed the Commission during the public information hearings in 1976 that it was investigating methods of reducing lead times. Details of these investigations were sought by the Commission and were to have been provided by Hydro in a separate submission.[10] This submission was not received.

Table 3.6 Representative Lead Times (in years) of New Thermal-Electric Generating Stations

	Nuclear 850 MW units (years)	Fossil-steam 750 MW units (years)	Fossil-steam 200 MW units (years)	Combustion turbine units (years)
Investigations and public participation culminating in approval to acquire a specific site	2–3	2–3	2–3	1
Specific site investigation and public participation, and preliminary engineering culminating in project release	3	3	3	1
Site preparation	1–3	1–3	1–3	–
Detailed design and on-site construction, up to in-service date of the first generating unit	5.5	4.5	3.5	1
Total lead time	11.5–14.5	10.5–13.5	9.5–12.5	3

Source: Ontario Hydro, "Generation Planning Processes", submission to RCEPP, May 1976, Exhibit 21.

However, Ontario Hydro testified during the public information hearings that a reduction in lead time in the third and fourth steps – site preparation, and design and construction – is not possible. Improvements in lead time are possible, according to Hydro, through the "project-on-the-shelf" concept by which sites are "banked" in advance by the completion of step one, that is, site acquisition, and certain activities in step two are carried out – up to but not including project approval, that is, site investigation and preliminary engineering work. This concept of site-banking could reduce the lead time from 11-14 years to 8-10 years for a nuclear station, from 10-13 years to 7-9 years for a large fossil-fuelled station, and from 9-12 years to 6-8 years for a smaller fossil-fuelled station. The cost of completing step one and part of step two could be $10-20 million – it was about $15 million for the Darlington station. While these costs are not insignificant, they are less than 1 per cent of the total capital cost of the project.

The Honourable Darcy McKeough, then Minister of Treasury, Economics, and Intergovernmental Affairs, in his appearance before the Commission during the public information hearings in 1976, outlined his Ministry's policy with respect to reducing lead times, and endorsed Ontario Hydro's position on the project-on-the-shelf concept and site-banking:

> It seems to me that if we have to look at everything in the context of a lead time of 12 years we are putting ourselves into a position we don't need to be in. We should, if I can put it simply, have a number of projects on the shelf in which the first six years is out of the way.... There would be a problem here to some extent of credibility both for Hydro and the government of raising some expectations or fears that might prove to be unnecessary, but it seems to me [that] if we can get two or three sites ahead and on the shelf, then we [can] shorten that whole period so that we can go full out on the last six years if that is required.[11]

The Sierra Club of Ontario, in its submission to the Commission in September 1978, supported the concept of site-banking and recommended that "the Commission give favourable consideration to land-banking as a significant aid to sound electric power planning".[12] While noting that "land-banking, properly administered, appears to be a reasonable 'insurance policy'", the club also proposed a set of guidelines for land-banking. The guidelines encourage public participation, environmental assessment, the use of multi-purpose transmission corridors, and the use of a generating site for a range of diverse options, but they caution against activities that may not be in the public interest:

> Land-banking should be undertaken to improve planning choices, facilitate environmental assessment and shorten the lead time between final identification of "need" for generation and plant commissioning. It should *not* be undertaken as a land speculation activity.[13]

The Sierra Club also recommended other means to reduce lead times, including the use of proven designs, the use of smaller-scale projects that create less conflict, and the establishment of a clear framework for decisions and approvals in order to minimize uncertainty.

It must be remembered that site-banking reduces the effective lead time only from the viewpoint of an upward flexibility in system planning, that is, only when the demand happens to be more than forecast. Ontario Hydro is expected to have considerable excess generating capacity until at least the late 1980s, on the basis of its 1979 load forecast. Volume 3 of this Report, which discusses the factors affecting the

demand for electricity, indicates that Ontario Hydro's 1979 load forecast may be too high. Furthermore, there is a potential to expand the generating capacity, especially nuclear, at some of Ontario Hydro's existing sites, e.g., Lennox, Darlington, and Wesleyville.[14] On the basis of Ontario Hydro's estimates of the "probable maximum capacity", these three sites could accommodate an additional thermal capacity (beyond the currently committed programme) in the order of 18,000 MW, which is more than Ontario Hydro's planned thermal capacity of 14,200 MW for the 1990s. Hydro has pointed out that the probable maximum capacity could be influenced by economic, socio-environmental, and technical factors.

The preceding discussion indicates that there is sufficient time, at present, for public participation and environmental assessment with regard to any new site proposal by Ontario Hydro. In the longer term, however, site-banking may play an important role in enhancing the flexibility of planning.

System Considerations

It is clear that many of the key variables that affect the planning of a system, such as the future demand for electricity, the availability of resources, and project in-service dates, are characterized by considerable uncertainty. The behaviour of the system in an uncertain future, in terms of its ability to survive disturbances, depends on its resiliency. A resilient system should be able to survive the disturbances and adapt to the changed conditions. The ideal way to cope with an uncertainty is to recognize it, estimate the system's probable behaviour in response to it, and allow for it in the design of the system. An example of a procedure for coping with uncertainty is the generating reserve margin, which incorporates an allowance for component failures. Various reliability models study the effect of such failures on the reliability of the electricity supply, and, on the basis of a specified reliability criterion, estimate the amount of reserve capacity required.

The resiliency of a system is enhanced if the system is made up of diverse components. It is desirable to incorporate diversity in the design of a system so that a breakdown of one major component will not necessarily cause the failure of the whole system. The same concept is applicable when a mix of generation technologies and primary fuels is chosen for an electric power system. If, for instance, a system were to be based exclusively on one source of primary energy, its whole operation could be crippled by a single event, such as a major drought, a prolonged strike of coal-miners, or a catastrophic accident in a nuclear plant.

An exception to this rule is seen in some systems that are largely hydraulic (such as Hydro-Québec). They usually have large storage capacity in lakes and a relatively small variation in annual precipitation, so that the chance of a major shortfall in water supply is very low. There is, of course, the possibility of a major outage caused by a design or operations error during the construction of the dams, or in the turbo-generators. However, there are usually many generating units per dam in a system, and the dams are distributed over several rivers, so that many fluctuations average out. Moreover, these are mature and well-established technologies, and the possibility of a major problem is much less than in a system that is dependent on emerging (or immature) technologies.

Although the Ontario Hydro system is well balanced at present among coal, nuclear, and hydraulic capacity, it is important to note the implications of the increasingly complementary nature of the largely hydraulic generating system in Quebec and the increasingly thermal generating system in Ontario. For example, a major fault in boiler design or manufacturing might require more than the usual number of Ontario Hydro's thermal units to be out of service for maintenance simultaneously. This sort of problem does not much affect Hydro-Québec, and so a mutual assistance agreement with Hydro-Québec would give Ontario a more resilient system. Similarly, the rivers that supply the bulk of Hydro-Québec's and Ontario Hydro's power come from different watersheds. Although the Quebec watersheds are replenished by the same east- or northeast-moving weather pattern that replenishes Ontario's watersheds, most of them are north of those in Ontario. Low-water conditions are unlikely to occur simultaneously in both provinces, so that in most circumstances the thermal and hydraulic generation in Ontario would be available to assist Quebec.

It must be pointed out that diversity of the fuel base is only one factor in the choice of a mix. The qualitative nature of this factor makes it difficult to incorporate it in quantitative decision-making models. However, a primary objective of generating mix studies is long-term reliability of the supply of energy, and so it is prudent to consider the effect on the system of interruptions to the energy supply.

Ontario Hydro's Practice in Assessing Generating Mix

The methods of quantitative analysis that are used by Ontario Hydro to assess generating mix incorporate factors such as economic costs, reliability, operating limitations, and capital or fuel-supply constraints. Ontario Hydro uses its judgement in the weighing of other considerations, such as socio-economic factors, fuel flexibility and security, and technical obsolescence.

As mentioned earlier, an economic cost comparison of the CANDU-nuclear and coal-fired power plants indicates a break-even annual capacity factor of about 40 per cent based on U.S. bituminous coal, and one of about 30 per cent based on western Canadian bituminous coal. This implies that the CANDU units are cost-effective when supplying loads lasting for as little as 30-40 per cent of the year. If cost economics were the sole consideration in the determination of the mix, the long-term share of nuclear and existing base-load supply could be as high as 70 per cent of system capacity and 90 per cent of system energy. This follows from the fact that about 90 per cent of the annual energy demand is contributed by loads prevailing more than 40 per cent of the time (see Figure 2.6 in Chapter 2).

As will be shown in Chapter 7, an analysis of Ontario Hydro's previous and current generation expansion programmes indicates that the planned long-term share of the nuclear and base-load hydraulic stations is roughly 60 per cent of the system capacity and 75 per cent of the energy. The difference between the planned mix and the mix dictated purely by cost economics is a measure of the weighing by Ontario Hydro planners of the benefits of diversity in the generating mix and the operating limitations of the CANDU reactors at low capacity factors:[15]

> ... there is a concern about fuel supply diversity and flexibility; a very real question: Should we go [all nuclear] if dollar and cents economics show we should be all nuclear? The dollar and cents [economics of] nuclear doesn't take into account flexibility and fuel security.
>
> Our system demand capacity factor couldn't tolerate ... that amount of nuclear ... just couldn't do it. The weekly and weekend and seasonal variations in load are such that we would have to examine how much load cycling the nuclear units have got to do. ... Whether or not they can meet the load increase in two hours every morning, might be another constraint.[16]

Ontario Hydro believes that the ability of the generating system to meet unpredictable conditions is improved if a thermal generating unit is able to use various alternate fuels. A good example of such flexibility is the R.L. Hearn Generating Station in Toronto. Built in the early 1950s, it was designed to burn coal, but in 1971, under new regulatory standards on environmental pollution, Ontario Hydro carried out alterations enabling it to burn either coal or natural gas. At the same time, Hydro also believes that it is uneconomic to design a plant initially to burn a range of fuels.

> Most fossil-steam units can burn only a small range of alternative fuels. This is because their capital cost must be increased substantially if they are designed to use a wide range of fuels; cost analysis indicates that it may be less costly to rebuild a boiler to meet a future major change in fuel than to spend larger initial sums of money to design the boiler ... for use of a wide range of fuels.[17]

However, Ontario Hydro acknowledged before the Commission in November 1978 that, while it is relatively simple to convert an existing coal-fired station to use oil or natural gas (as was the case with Hearn), it may not be technically feasible to do the reverse. This is because of the design of coal-fired boilers and associated coal-handling equipment such as pulverizers and conveyors. Burning coal produces much ash, the handling of which requires a different type of boiler bottom. Furthermore, there may be limited space for coal storage at an existing oil- or gas-fired station. An estimate of the increase in capital cost associated with building a boiler to burn oil as well as coal is 10-15 per cent of the cost of the oil-fired plant, according to a study done by Ontario Hydro in 1973.[18]

At present, oil and natural gas play a minor role in Ontario Hydro's system (see Table 3.1), and Ontario Hydro plans to build only one more oil-fired station (the 1,082 MW Wesleyville Station). Since oil-fired stations cannot be converted to burn coal and it seems quite unlikely that coal will be replaced by oil or natural gas in Ontario, the ability of fossil-steam units to burn other fossil fuels might not enhance the flexibility of Ontario Hydro's system to any significant extent. What may be more important is the ability of fossil-fuelled stations to burn biomass-derived fuels.

Operating flexibility is desirable, in the face of uncertain future load patterns. Due to the long lead times and relative operating inflexibility of large fossil-steam and CANDU units, operating flexibility of the system as a whole can be enhanced by the incorporation of short-lead-time storage plants:

> Both large fossil-steam and CANDU-PHW units have potential problems if they are operated on a highly cycled loading pattern. If changing conditions of future loads and generation tend to increase

> the cycling and to decrease annual capacity factors, the solution might be the introduction of energy storage schemes which would result in meeting cycling requirements and at the same time would preserve high annual capacity factors on the large thermal units.[19]

Any consideration of storage schemes must be based on factors such as their lead times, capital cost, reliability, input-output efficiency, and storage density. The most recent conclusion Ontario Hydro has reached, on the basis of studies of large-scale energy-storage alternatives, is that:

> . . . for early inclusion in Ontario Hydro's generation program the most economical large-scale energy storage alternative is pumped storage, either above ground or underground, and that no more than a watching brief should be kept on alternative storage technologies. Among the alternatives studied were: above-ground pumped storage; underground pumped storage; compressed air storage; feed-water storage in a pressurized underground cavern; lead acid battery storage; and steam storage in a pressurized underground cavern.[20]

The implications of storage in the Ontario Hydro system are considered in Chapter 8. Briefly, it may be said that pumped storage has quite a limited role to play in enhancing the operating flexibility of a planned generation programme when faced with lower than expected load growth, because the storage lead time is likely to equal that of a nuclear plant.

Summary and Conclusions

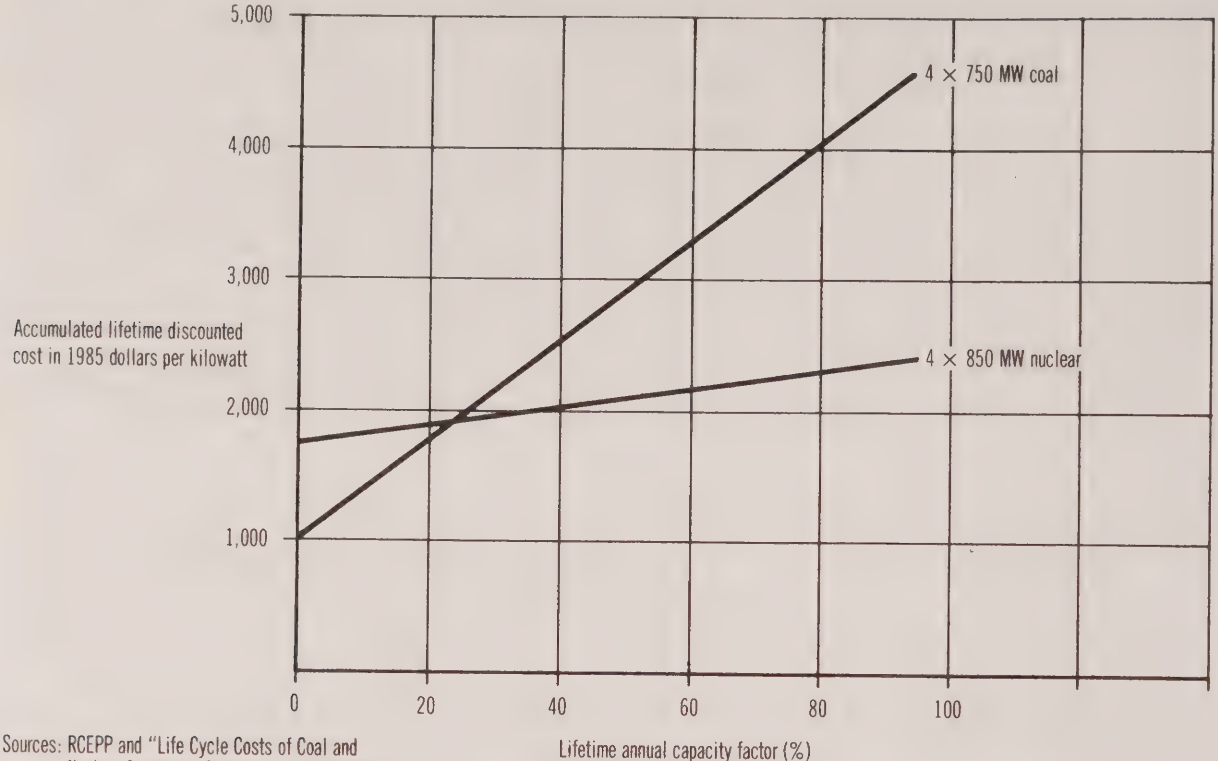
The mix of generating resources in an electric power system is affected by many factors, important among which are cost, reliability and performance, operating characteristics, fuel requirement and supply, lead time, and total-system considerations. An economic comparison of the conventional generation technologies used in Ontario indicates that, for base-load requirements, a new nuclear plant has a substantial economic advantage over a new coal-fired plant. The cost of geological disposal of spent nuclear fuel is quite uncertain but this cost has to increase by one order of magnitude to offset the advantage of nuclear. Oil- and gas-fired plants are economic for peaking and reserve, but, if such plants are used for decentralized applications in a co-generation mode, they may be economic at higher capacity factors.

An analysis of the reliability data for Ontario Hydro's thermal units shows that their performance has been as expected and that the CANDU units should be able to maintain base-load capacity factors. While CANDU units are not suitable for load-following, they can be shut down over weekends and can be operated at reduced outputs overnight. Hydro's CANDU units are planned for operation in this century only at base-load capacity factors.

Ontario Hydro's fuel supply appears reasonably secure. No problem in meeting the peaking and reserve requirements of residual oil- and gas-fired stations is foreseen. With respect to coal supplies, Hydro has a problem of oversupply until the late 1980s. After that, the requirements, which will not be much higher than current consumption levels, could be met by a combination of U.S. and western Canadian supplies. Hydro's current uranium contracts are adequate for the 30-year requirements of about 5,400 MW of uncommitted nuclear capacity (after completion of the Darlington Generating Station). Although the lead time of a major generating facility could be reduced from 13 years to eight years by site-banking, there is no urgency about doing this. Sufficient time is available for public participation and environmental assessment of any new site proposal by Hydro. In the longer term, site-banking may play an important role in enhancing planning flexibility.

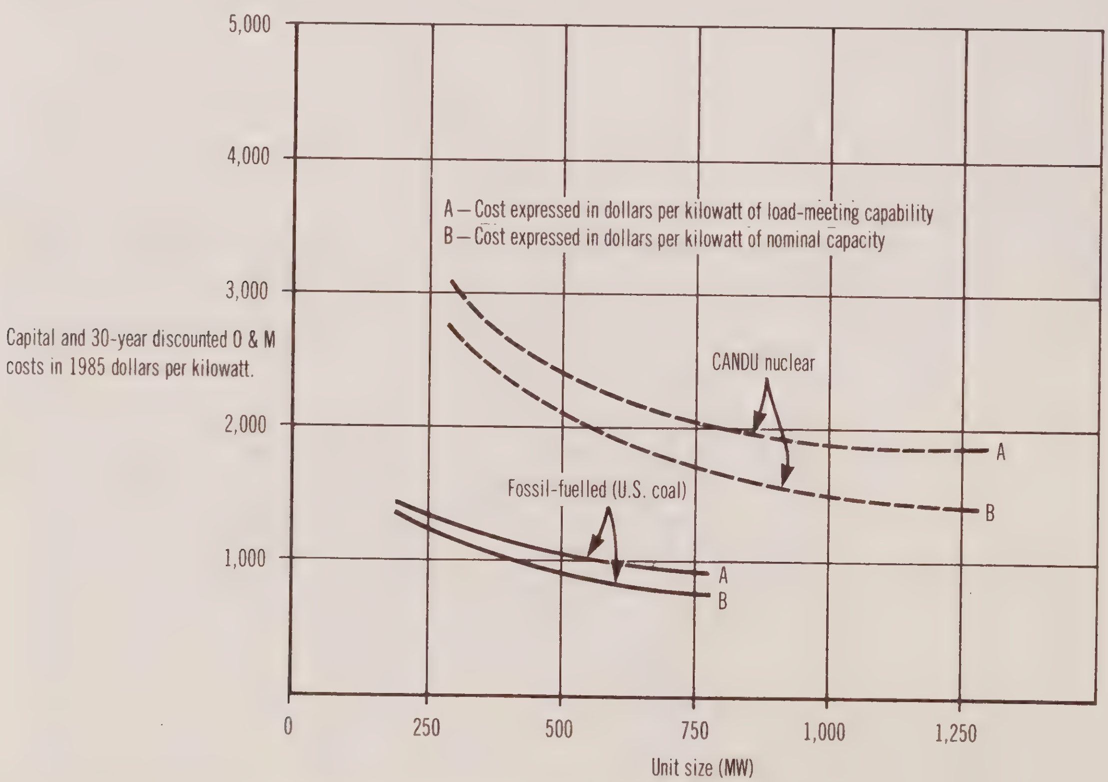
A major total-system consideration in the choice of a generating mix is the desirability of a diverse mix to increase the system's resilience and flexibility. In this regard it is important to note that although economics is the major consideration in Ontario Hydro's planned mix, operating limitations and fuel diversity are also given consideration. For example, the economics suggest that about 60 per cent of total system capacity should be nuclear, but Hydro's planned share of nuclear is about 50 per cent. The ability of Hydro's fossil-fuelled stations to burn alternate fuels might not enhance the flexibility to any significant extent, because, while it is possible to change existing coal-fired stations to burn oil or natural gas (such a shift is considered unlikely), the converse is not true. What may be more important is the ability of fossil-fuelled stations to burn biomass- or refuse-derived fuels. Operating flexibility, particularly of CANDU stations when faced with lower than expected load growth, could be enhanced by shorter lead time storage schemes to absorb surplus nuclear capacity during off-peak hours. However, this will not be possible with pumped storage (the most economical option), because its lead time is likely to equal that of a nuclear plant.

Figure 3.1 Economic Cost Comparison of a New Nuclear and a New Coal-Fired Generating Station Coming into Service in 1985



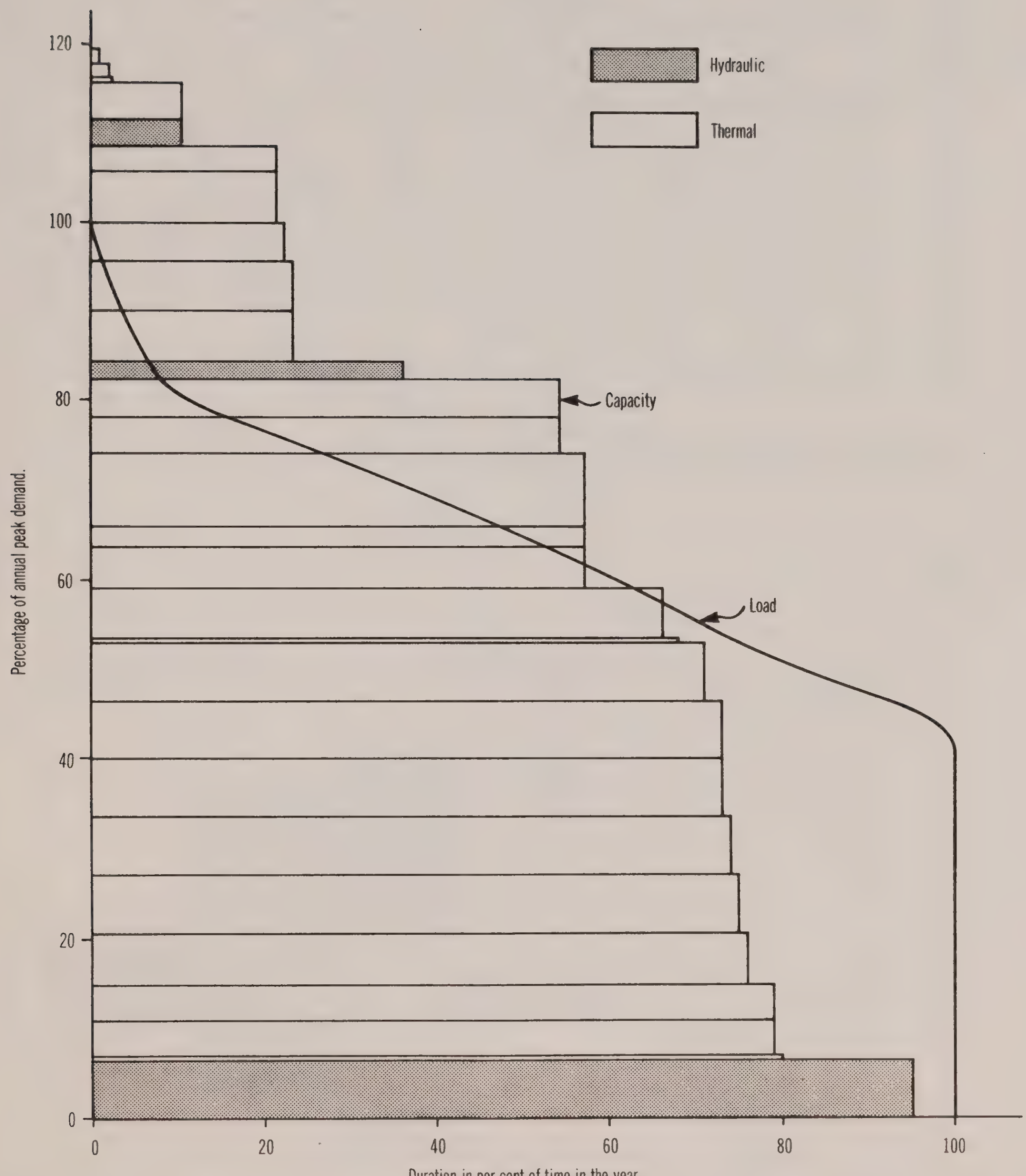
Sources: RCEPP and "Life Cycle Costs of Coal and Nuclear Generating Stations", by S. Banerjee and L. Waverman, July 1978; a study commissioned by RCEPP.

Figure 3.2 Cost of Generating Unit Unreliability



Source: "Generation Planning Processes," Ontario Hydro submission to RCEPP, May 1976, Exhibit 21.

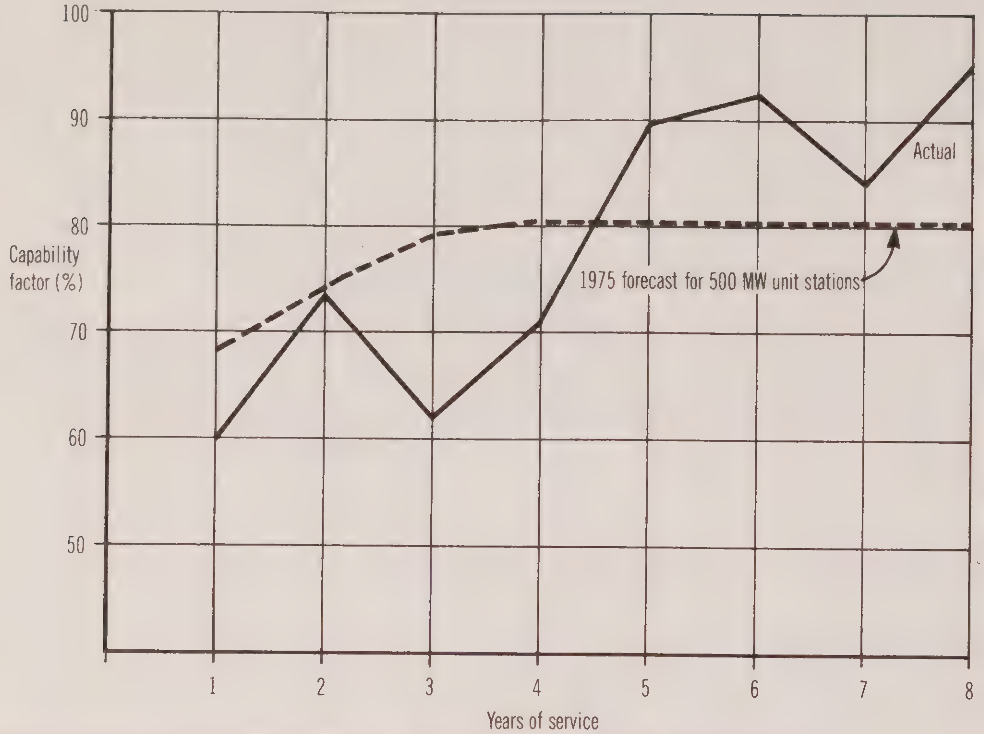
Figure 3.3 Distribution of Hourly Capacity and Load for Ontario Hydro East System



Note: The operating bands for hydroelectric capacity are rough approximations, because individual hydroelectric capacity factors will be distributed across the 0% to 95% range.

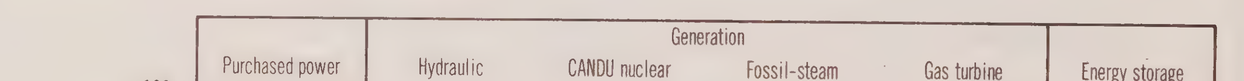
Sources: RCEPP and Ontario Hydro

Figure 3.4 Pickering A Generating Station — Capability versus Age



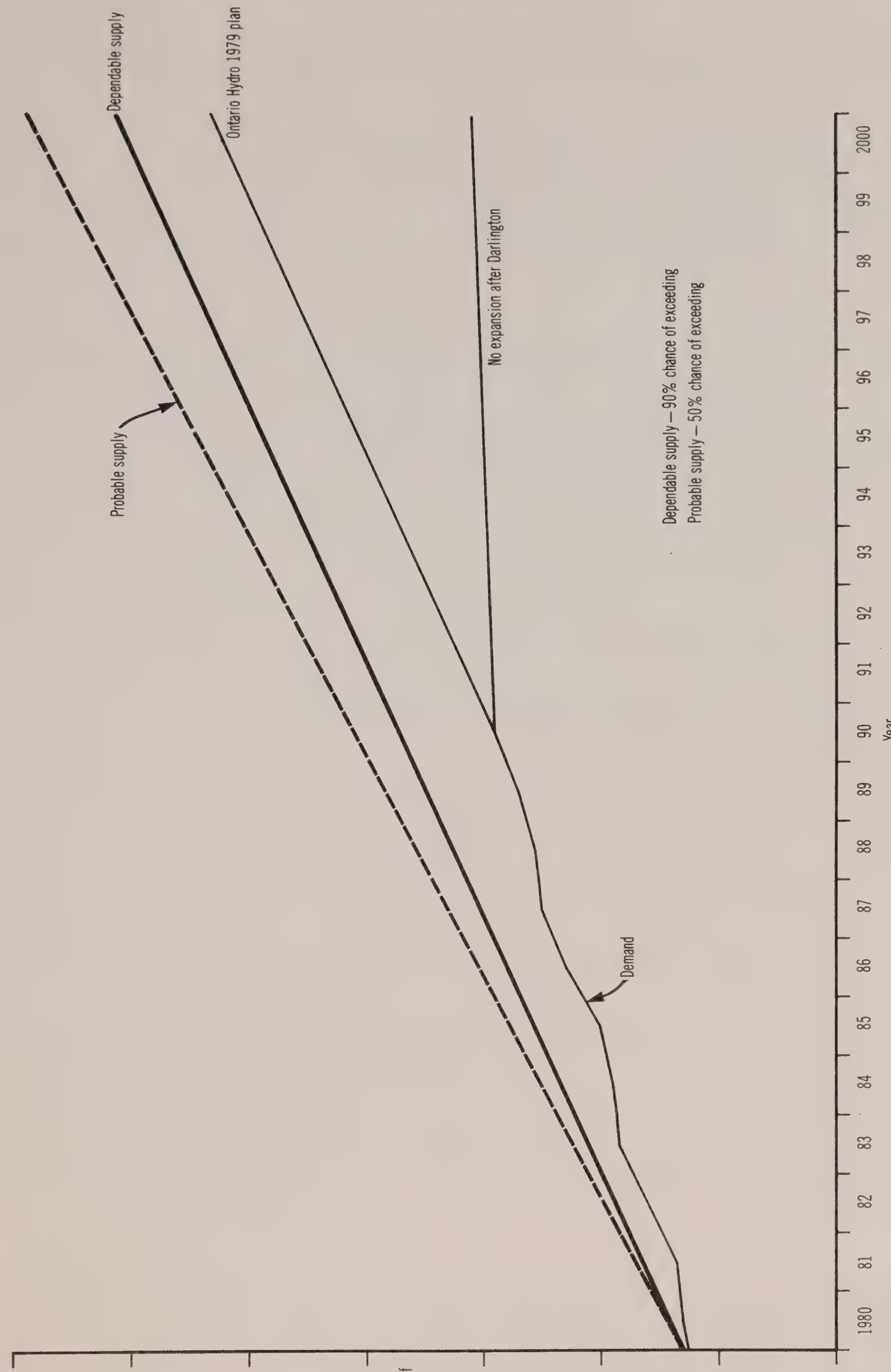
Sources: Table 3.4 and "Generation Planning Processes," Ontario Hydro submission to RCEPP, May 1976, Exhibit 21.

Figure 3.5 Efficient Operating Ranges of Conventional Power Sources



Source: "Generation Planning Processes", Ontario Hydro submission to RCEPP, May 1976, Exhibit 21

Figure. 3.6 Heavy Water Supply and Demand (BHWP-A and BHWP-B only)



Sources: RCEPP and Ontario Hydro.

CHAPTER FOUR

The Reliability of the Electric Power System

The reliability of a device or system is defined as the probability that it will fulfil its purpose adequately for the intended period of time and under the specified operating conditions. In the case of an electric power system, the purpose may be stated broadly as being to supply electricity to the customers with a high degree of continuity. As will be noted later in this chapter, an electric power system is so complex that it is neither feasible nor practical to express its reliability in terms of a single probability. The probability of a malfunction of a component of a power system, such as a generating unit, a transformer, or a transmission line is nevertheless an important consideration in any evaluation of power system reliability.

The causes of unreliability may be long-term or short-term in origin. Among the long-term factors that may affect reliability are the lead times (in the order of a decade) that are required for the installation of major new generation and transmission facilities and the uncertainty that surrounds the demand for electricity over such a long period. A project may fall behind schedule due to strikes, delays in equipment deliveries, mismanagement, or delays in obtaining government approval in matters that have political or socio-environmental implications. Because of the length of the lead time, the chance of offsetting such a delay by advancing the schedules of other projects is likely to be poor. Even if there is no delay in the in-service date of the project, the actual demand for electricity may by then differ significantly from the forecast demand, in level, in load shape, or in geographical distribution. Another uncertainty in the long term has to do with the effective utilization of generating capacity. Actual output may be constrained by changes in environmental regulations, by fuel shortages, or by droughts.

In day-to-day operations, the predominant source of unreliability is the unavoidable or unexpected forcing out of service of part of the supply system. A generating unit may be forced out of service by a component breakdown caused by wear and tear or by inherent defects. A transmission line may be disrupted by lightning. Every generating unit must be removed from service periodically for preventive maintenance, to reduce the incidence of unexpected failures. Another short-term consideration that may cause a shortage of capacity is an increase in demand as a result of changes in the weather or in the level of economic activity.

A utility's customers require a degree of reliability that is considerably higher than the degree of reliability of the individual components of the system. It is necessary to have spare components, and spare capacity, so that the system can continue to supply users satisfactorily when some of its components are unavailable, and to provide against the other contingencies that have been mentioned. Additional capacity for generation is called reserve generating capacity, and for reasons of fuel economy it is used only when necessary. Reserve capacity is commonly referred to as "reserve margin"; it represents the difference between the generating capacity and the peak demand, expressed as a percentage of the peak demand. In Ontario Hydro's system, for the purposes of reliability evaluation and system planning, the peak demand is divided into two categories – primary peak and firm peak. Firm peak is defined by Ontario Hydro as the peak demand that must be supplied to the customers with a high degree of continuity. Ontario Hydro also offers its large industrial and commercial customers "interruptible" power, which is supplied at a lower level of reliability but at cheaper rates. As the name implies, this service may be interrupted at times when the system supply capability is unable to sustain it. The primary peak demand is the sum of the firm peak demand and the interruptible power. The generating reserve margin in Ontario Hydro's system is usually expressed as a percentage of the firm peak demand. A measure of reserve capacity for the bulk power transmission system is not available. As will be discussed later, the reliability of a transmission system depends more on the behaviour of the system as a whole than on the reliability of its individual elements.

Availability and Security

Since the electric supply system is made up of three major subsystems – generating stations, bulk power transmission lines, and a complex distribution network – the reliability of supply to the customer, for a known demand, depends on the reliability of these three components as well as on the design and operation of the interconnected system.

Recently, Ontario Hydro undertook customer surveys to determine the costs imposed on customers by

supply outages of varying frequency and duration, and it is attempting to relate this information to the design of the system. However, traditionally, the reliability of each of the major subsystems has been assessed separately and on the basis of different performance criteria.

The traditional methods of reliability analysis assume that the reliabilty of each major subsystem must be assessed from two aspects – "availability" and "security". Availability refers to the performance of the individual components of a system (generating units, transmission lines, transformers, circuit-breakers). It is defined as the expected percentage of the total time during which the component is required, that is, not out of service due to a fault, an equipment failure, or incorrect operation or maintenance. Thus, when we say that the availability of a generating unit is 80 per cent, we mean that, on the average, the unit will be unavailable for 20 per cent of the time. Component availability is estimated from the outage records. These data are essential in evaluating subsystem reliability.

Security is a term that is applied to an electric power subsystem or to the system as a whole. It is defined as the ability of a system to withstand transient disturbances and regain an acceptable operating state. An acceptable operating state exists when the voltages and line loadings across the system are within acceptable limits. After a major disturbance, which may be caused by a transmission line fault, the loss of a large generator, or a sudden large change in the load on the system, the system enters what may be called a dynamic state. While the system is in a dynamic state, the power flows and the voltages across the system are changing continuously as the system seeks a new balance to satisfy the changed conditions. If a satisfactory new balance can be achieved, the system is then said to be secure. If the power swings increase in magnitude to such an extent that instability results, leading to the disconnection of generators and lines by protective devices, and eventually perhaps to widespread and lengthy power interruptions, the system is not secure. It is stressed that, although a system may be stable, it is not secure unless it regains an acceptable operating state after the disturbance.

The massive northeastern black-out of 1965 is a classic example of an insecure system. An outage on Ontario Hydro's transmission lines running west from the Sir Adam Beck Generating Station at Niagara Falls blocked the flow of power towards Hamilton and Toronto, blacking out southern Ontario. The Niagara power took the only path open to it and rushed over the interconnections into New York. This sudden surge of power caused a variety of overload protection relays to trip in a cascade that led to a collapse of the entire New York system and the systems of the adjoining states.

Table 4.1 summarizes the availability and security aspects of reliability in the major subsystems of an electric power system.

Table 4.1 Steady-State (Availability) and Dynamic (Security) Aspects of Power System Reliability

	Steady-state aspect			**Dynamic aspect**
Subsystem	Generation	Transmission	Distribution	Bulk power (generation and transmission)
Typical failure causes	Generator outages	Line or transformer outages	Line or transformer outages	Multiple line outages in a short time
	Unexpected load	Unexpected load	Unexpected load	Protection system failure
Resulting conditions	Generation deficiency	Line overload	Line overload	Cascading outages
	Energy deficiency	Low bus voltage	Low bus voltage	Instability
Service consequences	System voltage reduction	Low voltage (areawide)	Low voltage (local)	System blackout
	Systemwide load reduction (selective customer interruptions)	Areawide load reduction (selective customer interruptions)	Local load reduction (customer interruptions)	

Source: "EPRI Journal", Electric Power Research Institute, Vol. 3, No. 10, December 1978, p. 10.

Availability and Security in the Generation Subsystem

As far as the reliability of a generating system is concerned, the availability of a generating unit is the predominant factor. Availability accounts for both scheduled and unscheduled shut-downs of the unit. Various indices are used by utilities to express generating unit availability. The following four are appropriate for this discussion: the forced outage rate, the planned outage rate, the maintenance outage rate, and the capability factor.

The "forced outage rate" (FOR) is the ratio of forced outage hours to the sum of operating hours and forced outage hours. It is a measure of the incapability of a generating unit to produce energy due to

forced shut-downs. Forced outages are random in nature and require a unit to be derated or taken out of service as quickly as possible.

The "planned outage rate" (POR) is defined as the fraction of a period, e.g., a year, when a generating unit is out of service for planned maintenance. Planned maintenance includes major overhauls to reduce the incidence of forced outages, and it may be postponed from one season to the next. It is scheduled months in advance and is generally carried out annually during the season of low loads.

Maintenance outages, like the forced outages, are random in occurrence but they do not require a unit to be derated or taken out of service immediately. They are generally scheduled for "safe" periods when they will not interfere with the utility's ability to supply the load fully, e.g., during nights or at weekends. The "maintenance outage rate" (MOR) is the fraction of a period when a unit is on maintenance outage.

The "capability factor" is a measure of the ability of a generating unit to deliver energy in the absence of any problems or restraints external to the unit.[1] It is expressed mathematically as (1-FOR)(1-POR-MOR). The capability varies with the type and size of the unit. Hydraulic units are the most reliable. The average capability factor of Ontario Hydro's hydraulic units is about 95 per cent. Large thermal generating units have mature capability factors in the range of 75 to 80 per cent.

The outages for a generating unit are generally highest during its initial years of service. With time the unit "matures", the outages decrease, and the capability increases to a mature value. As an example, Ontario Hydro's forecasts of the first-year and the mature capability factors of a 500 MW CANDU generating unit are 68 per cent and 80 per cent, respectively. The maturing period is in the order of four to five years for large thermal units.

Security is not a prime concern in assessing the reliability of a generating system. Generating system security is inherently high because (a) generating units are designed to limit the number of sudden losses of generating capacity, and the design of the bulk power system is aimed at accommodating losses that do occur, and (b) generating stations are designed to cope with sudden stresses that may be imposed on them by problems in the bulk power transmission system. It should be noted, however, that for certain disturbances and transmission line outages it may become necessary to "reject" generation in order to improve the transient stability of the bulk power system. Generation rejection means disconnecting one or more generating units from the bulk power system to reduce the excess power. Hydraulic units are quite rugged and are therefore preferred for rejection. While the thermal units are also designed to withstand the shocks caused by sudden disconnection, frequent rejection at full load may cause damage and so reduce their availability.

Availability and Security in the Transmission Subsystem

The role of a transmission system may be stated, in general, as being to provide a link between the generating stations and the system load. Since there are many generating stations and many load centres, the link is in the form of a network. The availability of the elements of this network is largely a function of their failure and repair rates. Individual transmission elements tend to have much higher availability than generating units. This is particularly true of the Ontario Hydro system; in 1974, the availability of its major transmission lines averaged 98.8 per cent.

However, from the viewpoint of the reliability of the bulk power transmission system, security rather than the availability of transmission components has traditionally been the main consideration in transmission planning in Ontario. Transmission planners historically have recognized that the transmission system has the potential for producing complete system collapse – as was vividly demonstrated in the northeast black-out of November 1965, and again in July 1977 in New York City. A bulk power transmission system is a highly complex mechanism. Its behaviour under abnormal conditions is correspondingly difficult to predict. For example, a transmission line may be subject to different types of faults (e.g., lightning or physical damage causing a short circuit) at a variety of locations along its length. The dynamic behaviour of the whole transmission system will depend on the nature of the fault, its location, and the events immediately after its occurrence, namely, how rapidly the faulty line is removed from service by automatic protection and control devices, whether an immediate automatic attempt is made to restore the line to service, and whether or not this attempt is successful.

Because of a transmission system's complexity, no quantitative index of its security is available. The transmission planners usually carry out simulation studies to determine a system's ability to survive certain postulated events (events that are severe but credible) without causing cascading failures and

system collapse. If the system can survive these events, it is expected to survive any others. The selection of these postulated contingencies requires the exercise of mature judgement based on broad experience. This judgement is now being augmented by computer-aided security assessment.

Availability and Security in the Distribution Subsystem

Of principal interest at the distribution level is the availability of components and the continuity of service at the customer's premises. An outage of a single component of the distribution system generally leads to a local interruption of power of the sort that is responsible for the greater part of the customer interruption time. The outage may be caused by equipment malfunction or by some external event such as lightning, a storm, or the collision of a heavy vehicle with a distribution pole. Prolonged power black-out may result if, after a lightning strike on a distribution feeder, the circuit-breaker at the distribution station fails to close again.

The security of the distribution system is of little consequence, since disturbances on the distribution network generally have little impact on the bulk power generation and transmission system.

Reliability Evaluation

Reliability evaluation deals with the question: What increase in reliability is associated with adding a piece of equipment to the system, or, What is the reliability of the system with and without the additional equipment? Power system planners have been trying for decades to develop ways of producing consistent yardsticks of power system reliability. Without such yardsticks, reliability evaluation has to depend heavily on experience and judgement. The reliability levels of alternative plans with different equipment sizes or equipment availabilities cannot be compared accurately; the effect of changing load patterns on system reliability cannot be accurately assessed. Without yardsticks of reliability, it is difficult to take these complexities and uncertainties into account in the planning process. It is, also, difficult to quantify the conclusions – to state with any certainty why new facilities are needed and when they should be added.

Ideally, the methods used for evaluating reliability should produce measures, or indices, of at least three significant consequences of a failure to provide electrical service. These are:

- the magnitude, in terms of power and energy, of the electrical load that fails to be supplied in each occurrence of failure
- the frequency with which the load fails to be supplied
- the duration of each occurrence.

All three measures are important because the benefits of reliability, or the customers' perceptions of the cost of unreliability, depend on the magnitude, frequency, and duration of an outage. In the opinion of the electricity industry, a quantitative expression of the three consequences of a failure to supply is an adequate measure of the reliability of an electric power system.

Since the purpose of an electric power system is to provide its customers with a reliable supply, the three indices of service quality must be known at the customer end. This entails the evaluation of the reliability of each subsystem – generation, transmission, and distribution – using a common methodology for all three so that the reliability of the subsystems can be combined to give the customer an index of overall reliability. At present, the reliability of each subsystem is evaluated separately, and a different methodology is used in each case. Workable techniques for measuring the reliability of a total power system, as viewed from a customer's premises, do not exist.

What follows is an outline of the techniques commonly used in evaluating the reliability of the generation, transmission, and distribution subsystems, and of efforts that have been made by Ontario Hydro and other utilities to improve these techniques and integrate them so as to produce a measure of reliability from the customer's viewpoint.

Generation Reliability Evaluation

The reliability of the generating system has long been a matter of primary interest to the electricity utility industry. Probability techniques for estimating the generating reserve requirements have been in use for many years. The basic concern has been the provision of sufficient reserve capacity to assure within reason that available capacity will not fall short of load requirements at any time due to forced outages of generators, generator maintenance requirements, or load-forecast uncertainties. Several papers have been published on probability methods for the evaluation of generation reliability,

and the developments that led to the techniques now in use are interesting. The application of probability techniques in this field was discussed as early as 1933, but it was not until 1947 that the first major papers were published. These papers advanced some of the concepts on which the methods in use today are based. These methods, with some modifications, are generally known as the "loss of load approach" and the "frequency and duration of outage approach".

Although these techniques are available, many of the smaller electricity utilities still employ generation reliability standards that are based on deterministic methods dating back to the early days of the industry. These include the "per-cent reserve" method, in which generating capacity is added to the system to maintain the reserve at a given percentage value of the annual peak load, and methods expressing reserve in terms of the capacity of the largest units in the system (e.g., "reserve equal to 150 per cent of the capacity of the largest unit" or "reserve equal to the capacity of the two largest units"). Deterministic rules are arrived at by judgements based on experience and historical observation. Deterministic methods do not provide for any quantitative assessment of the reliability of various generation planning alternatives. Yet they are in widespread use, probably because of their simplicity. A survey conducted by the Canadian Electrical Association in 1974 indicated that only four of the 13 Canadian electricity utilities canvassed used probability methods to calculate generation reliability.[2] The other nine used "per cent reserve", the size of the largest unit, or a combination of these two as the criterion for planning generation. It must be noted, however, that most systems using the deterministic rules undertake probability studies periodically to confirm the adequacy of these rules.

On the other hand, the methods based on probability analysis can take into account the effect on reliability of such factors as the size, type, and number of generating units, the availability of the units, interconnections among systems, the shape of the load curve, and the uncertainty of load forecasts. Thus, probability methods can provide a consistent basis for comparing various planning alternatives, and they are far more useful to the system planner than simple deterministic rules.

The Loss-of-Load Probability Method

The probability technique most widely used by the electricity utilities for estimating the reliability of their generating systems is the loss-of-load probability (LOLP) method, or, as it has more recently and perhaps more correctly been termed, the loss-of-load expectation method. This method computes the expected (long-term average) number of days per year on which the available generating capacity is not sufficient to supply all of the daily peak load. The basic assumptions of this method may be summarized as follows:

- Transmission and distribution limitations are neglected and the total generation and load are assumed to be concentrated at the same point in the system.
- Generating units are assumed to be independent of each other. That is, it is assumed that the outage of one unit will not affect the operation of the others.
- Load is represented by the daily peak loads. It is assumed that if there is enough capacity to supply the daily peak, the rest of the daily load can be supplied.
- At the time of the daily peak, all of the generating capacity that is not on forced or scheduled outage is assumed to be available to supply load.
- It is generally assumed that generating capability will not be limited by fuel shortages. However, it is possible to analyse the effects of such limitations, if necessary.

Basically, a probability distribution of the amount of generating capacity that is likely to be rendered unavailable by an outage is obtained from data on the sizes and forecast outage rates of the generating units comprising the system. The capacity of the equipment that is out of service is considered to be a load on the system and is therefore added to the daily peak loads by combining the distribution of the capacity on outage with the distribution of the daily peak loads over a given period, for example, a month. From the resulting distribution of "equivalent load", it is possible to determine the probability that the equivalent load is higher than the peak installed capacity during the chosen period. This probability is the LOLP for that period. The LOLP can be translated into the expected number of loss-of-load days by multiplying the probability by the number of days in the period. The analysis can be repeated for other periods to obtain the loss-of-load days per year.

Among the utilities using the LOLP method for planning generation, a commonly accepted value of the reliability index is 0.1 days per year or one day in 10 years. This means that sufficient generation capacity will be installed that the expected number of loss-of-load days in a given future year will be no more than 0.1. In the past, Ontario Hydro has used this value as its target for generation reliability.

Hydro's LOLP method is similar in principle to, but different in details from, the LOLP computations made by other North American utilities. Hydro's technique calculates the LOLP on a month-by-month basis by making appropriate allowance for the generating capacity that will be on planned maintenance. As far as the load model is concerned, Hydro considers only the firm 20-minute peaks on the working days (the peaks on weekends and holidays are usually low enough that the chance of insufficient generating capacity at such times is negligible). This amounts to about 240 working days per year and the corresponding target LOLP is 1/2,400. Hydro schedules the maintenance of its generating capacity in such a way that the LOLP in each month is in the neighbourhood of 1/2,400, the so-called "equal risk criterion". Very little maintenance is carried out during December and January. Thus, Hydro's reliability calculations are, in effect, based on a policy of providing reserve against any forced outages of generating units during these months. The reserve against the planned maintenance of generating capacity is provided, in effect, by the lower loads that occur during the off-winter months (see Figure 2.5 in Chapter 2).

The reserve margin required for a given LOLP, such as 1/2,400, depends very much on the forced outage rate and on the size and number of generating units in the system. For the Ontario Hydro system, the reserve requirements have been in the 25 to 30 per cent range for an LOLP of 1/2,400, taking no account of the assistance available from the interconnections with neighbouring systems. Figure 4.1 gives an indication of the sensitivity of the LOLP in Hydro's system in response to variations in the generating reserve margin. The reference value for the reserve margin is that which results in an LOLP of 1/2,400. The estimated variation in Figure 4.1 is derived from Hydro's long-range forecasts LRF 48 and LRF 48A. As may be seen, the computed LOLP changes exponentially with the reserve margin, expressed as a percentage of the peak load. A 5 per cent variation in reserve margin changes the LOLP by more than an order of magnitude.

Fig. 4.1: p. 54

While reliability depends on a multitude of factors, significant among factors that are amenable to the widely used probability methods are: unit forced outage rate; unit size; the availability of assistance from neighbouring systems; and the uncertainty about the size of the load and about the in-service dates of generating units. The following is a discussion of the effect of these factors on the reserve margin requirements for the Ontario Hydro system.

Figure 4.2 indicates in a general way the reserve generation requirements associated with generating units of different sizes and forced outage rates. It illustrates this by considering the effect of adding a number of identical generating units to Ontario Hydro's existing, under construction, and committed system (with a generating capacity of about 33,000 MW) for the purpose of supplying an additional load of 5,000 MW with a specified LOLP of 1/2,400. The reserve is the difference between the additional generating capacity and the incremental load, expressed as a percentage of the incremental load. It is natural to expect system reliability to deteriorate, or reserve requirements to increase, with an increase in the forced outage rates of units, other factors remaining constant. Figure 4.2 shows that, if a 5,000 MW increment in load is to be supplied by 750 MW units with a forced outage rate of 10 per cent, the reserve requirement is about 21 per cent, that is, a total additional generating capacity of 6,050 MW. If the forced outage rate is 7.5 per cent, it is 14 per cent; and if the forced outage rate is 12.5 per cent, it is 27 per cent.

Fig. 4.2: p. 54

As for the effect of unit size on generation reliability, a system containing twenty 100 MW units is more reliable than one containing ten 200 MW units with the same forced outage rates. As an illustration, consider one 100 MW and two 50 MW units, each with a 10 per cent probability of failure. With the 100 MW unit, the probability of a loss of 100 MW of generating capacity is 10 per cent, compared with 1 per cent in the case of the two 50 MW units. Thus, the reliability of a generating system deteriorates as the size of the units in relation to total system capacity increases, or as the number of units decreases. Figure 4.2 shows that the reserve requirements associated with the 750 MW units with a forced outage rate of 12 per cent are 26 per cent of the incremental load; but, with 1,250 MW units of the same forced outage rate, they are 37 per cent of the incremental load.

Interconnections between systems improve the overall level of system reliability. In the case of two interconnected systems, the reliability of both systems is enhanced by the diversity in the occurrence of outages of their generating units. That is, there is some chance that, when one system is unable to supply its load completely, the other may, at that time, have surplus generation available that can be transferred across the interconnection to supply the first system's load. At other times, the situation may be the reverse, with the second system receiving assistance from the first. This kind of assistance allows each of the interconnected systems to operate with less reserve than it would require under the

Fig. 4.3: p. 55 conditions of isolated operation. This possibility is illustrated in Figure 4.3. The figure shows the results of a hypothetical situation in which Ontario Hydro's existing East System, along with the Pickering B generating station (with a total generating capacity of about 26,300 MW), has been interconnected with another, identical, system. With an interconnection capacity of 2,000 MW, each system can reduce its reserve requirement by about 1,400 MW (compared with the situation when they are not interconnected) and still maintain the same level of reliability with an LOLP of 1/2,400. Figure 4.3 also shows the corresponding results for two lower levels of generation reliability. Another interpretation of Figure 4.3 is that, if the reserve margin in each of the interconnected systems is held constant, then the reliability of each system increases with interconnections. Interconnections can also be beneficial, in the matter of reserve requirements, if there is diversity in the loads of the interconnected systems. Such diversity may be in the form of a seasonal climatic diversity, e.g., as between New York and Ontario, or in the form of a daily time-zone diversity, e.g., as between Manitoba and Ontario. The extent of the benefits of diversity between two systems depends on the amount of diversity, institutional arrangements, and the maintenance schedule for generating units. Interconnections also tend to reduce the shocks caused by major contingencies and to facilitate economizing transactions. These issues are discussed in a later chapter. The discussion of the effect of interconnections on system reliability will not be complete without mention of a major disadvantage of interconnections: interconnections make the operation of the power system more complex, necessitating constant co-ordination among member systems.

The effect on generation reliability of the uncertainty concerning the size of loads and the in-service dates of units depends on the nature of the uncertainty. Most load forecasts deal with the most probable load in a given future year, so that there is equal probability that the load will be greater or smaller than the forecast size. It is evident from Figure 4.1 that the reliability decreases more and more rapidly as the reserve margin is reduced. Thus, the expected value of reliability, if the size of the load is uncertain, will generally be lower than the value corresponding to the most probable load. The uncertainty of the in-service dates for new units may be treated in the same manner as the uncertainty about the size of the loads; delays in in-service dates are equivalent to higher-than-expected loads, and units coming into service before their expected dates tend to increase the reserve margin, as do lower-than-forecast loads.

Variations in the Use of the LOLP Method

While the LOLP method has gained reasonably wide acceptance, variations in the way in which electricity utilities apply it, and dissimilarities in the utilities' system characteristics and configurations, can lead to appreciable differences in reliability levels and reserve margins, even though the basic reliability criteria are essentially the same. As a simple illustration, Ontario Hydro, Hydro-Québec, and Manitoba Hydro all use a reliability criterion based on an LOLP of "one day in 10 years" for determining generation reserve capacity.[3] However, Ontario Hydro incorporates only working-day peak loads over a month in its LOLP model, whereas Hydro-Québec uses a monthly load-duration curve representing loads on both weekdays and weekend days. Thus, the risk index of one day in 10 years means an LOLP of 1/2,400 to Ontario Hydro but an LOLP of 1/3,650 to Hydro-Québec. On the other hand, Manitoba Hydro's model is based on only the weekday peak loads in the month of January, but the risk index in days per year is obtained by multiplying the LOLP by 365. And there are other differences between the utilities with respect to the assumptions they make when evaluating reliability by the LOLP method. Most utilities do not consider interconnection assistance in their LOLP computation. But those who do this use a lower risk index; for example, Manitoba Hydro uses a risk index of 0.003 days per year when considering interconnection assistance. Some utilities recognize the uncertainty of load forecasts in their computations and others do not.

It is clear, then, that an LOLP risk index of 1 day in 10 years may result in different generation reliability standards. For a particular utility, the strength of the LOLP technique may lie in its relative simplicity and in its ability to compare the reliability of alternative generation plans by analysing the effects of unit size and the forced outage rates of units, the uncertainty of load forecasts, and the availability of assistance over interconnections. This technique falls far short of providing an adequate measure of reliability for a given generation plan in the matter of the size, duration, and frequency of interruptions to the supply. Since the LOLP technique uses only the probability of an outage of a generating unit, it can make no prediction about the frequency of interruption, that is, the "how often" aspect of reliability. (It should be noted that the LOLP risk index of 1 day in 10 years must not be looked upon as the expected frequency of capacity shortages. Such an index only expresses the probability in

lay language.) Nor does the LOLP method provide any measure of the magnitude of an interruption in terms of power or energy, or of its duration.

The Frequency and Duration Method

These shortcomings of the LOLP technique led to the development of the frequency-and-duration-of-outages (F&D) method. This method recognizes the failure and repair rates of generating units, and not just the forced outage probability, and gives a more complete and useful measure of generation reliability. The relationship between the three quantities is illustrated by the following example. If a generating unit fails, on the average, every 100 days (0.01 failures per day) and it takes 25 days, on the average, to repair it (0.04 repairs per day), then the forced outage probability is 0.2. The F&D model consists basically of two parts: a capacity model and a load model. From the data on the sizes, the failure rates, and the repair rates of generating units, the capacity model can calculate the frequency and duration of each capacity-on-outage state. The load model calculates the frequency and duration of assumed load levels from the daily load cycles over the period concerned. The two models are then combined to produce the desired index of reliability in terms of the frequency, the duration, and the magnitude of capacity shortages.

In response to recommendation III-19 of the Select Committee of the Ontario Legislature in June 1976, Ontario Hydro has developed a programme based on the F&D method to evaluate the reliability of its generating system. This programme was used by Hydro in its System Expansion Program Reassessment (SEPR) study to complement the results of the LOLP technique. Table 4.2 provides a comparative assessment of the features of these two techniques as used in the SEPR study. The methodology used in SEPR to assess reliability will be discussed later.

Table 4.2 Features of the Loss-of-Load Probability (LOLP) and Duration (F&D) Reliability Computations of Ontario Hydro

Feature	LOLP	F&D
Load model		
Peak loads		
– Weekdays	December only	Yes
– Weekends	No	Yes
Off-peak loads	No	Yes
Load forecast uncertainty	No	Yes
Interruptible loads	Yes	Yes
Managed loads	Peak load reduced by a fixed amount	Simulation of effects for daily peak modification
Generation model		
Existing plant	Yes	Yes
Proposed plant	Yes	Yes
In-service date uncertainty	No	Yes
Output during commissioning	No	Yes
Variation in thermal unit outputs due to normal temperature changes	Yes	Yes
Reduction in output due to known government regulations	Yes	Yes
Variation in output from Sir Adam Beck G.S. due to normal river-flow variations	Yes	Yes
Energy production limits at other hydraulic stations	No	Yes
Planned outages	Yes	Yes
Maintenance outages	No	Yes
Forced outages and derating	Yes	Yes
Immaturity effects on outage factors	Yes	Yes
Uncertainty in outage factors	No	No
Common cause failures	No	No
Malicious damage, sabotage	No	No
Shortage of critical materials	No	No
Strikes	No	No
Failure in delivery of purchased firm power	No	No
Need to maintain operating reserve	No	No

Source: Ontario Hydro, System Expansion Program Reassessment Study, Second Interim Report, November 1978, p. 11.

Transmission Reliability Evaluation

The techniques available for evaluating the reliability of the bulk power transmission network are not as well developed as those for evaluating generation reliability. This is primarily because of the difficulty of defining what is and what is not a failure in a network system and in understanding the complicated and interrelated nature of events leading to a failure. In the generation sector, a failure is said to occur when "available generation is less than load", and this is usually caused by overlapping outages of several generating units. Similarly, in the distribution sector, a failure is defined as an interruption of customer supply caused by the outage of a component of the distribution system, such as a distribution feeder. A similar definition can be used for the transmission sector, and, in fact, existing transmission reliability models are based on this definition. But since transmission, in general, is a link between generating stations and distribution centres, the bulk power transmission design philosophy has traditionally been to avoid "widespread", "cascading", and "uncontrolled" power interruptions. Such interruptions usually are not the result of overlapping outages of one or more components, but of a chain of events having some interrelationship.

The ability of a system to avoid widespread black-outs is established by security analysis. Transmission planners carry out a mathematical simulation of the bulk power system on a computer. The system is subjected to selected fault conditions, fault-clearing sequences, and other contingencies that are severe but nonetheless credible, and then it is determined whether the resulting modelled transmission performance (voltage levels, line loadings, and the like) is within acceptable limits. The disturbances chosen for simulation are based on the experience and judgement of the planner. Sufficient transmission is then planned to maintain system performance despite the occurrence of the more likely outages (e.g., failure of a single line). However, some deterioration in system performance may be tolerated for less likely circumstances, such as multiple line outages or the loss of an entire power plant. The idea behind this approach to transmission planning is to reduce the chances of widespread black-out, but, if it occurs, to limit its impact in terms of the number of people affected and to reduce the time it will take to restore service.

Ontario Hydro, along with the New Brunswick Electric Power Commission and 19 utilities in the northeastern U.S., is a member of the Northeast Power Co-ordinating Council (NPCC), which was set up in the wake of the massive black-out of November 9, 1965. The council acts as a central co-ordinating agency for the planning and operation of the interconnected utilities' power systems to ensure adequate reliability of service to the customers of each system. The NPCC has formulated guidelines for the design and operation of the interconnected systems and these have been adopted by the member systems. The three key principles embodied in the guidelines are:

- There should be adequate transmission capacity to ensure that, in the event of the failure of a system element such as a generator, a transmission circuit, a transformer, or a circuit-breaker, no cascading outages or major power interruption will occur.
- The system should be operated within limits so that the loss of one element of the system will not precipitate cascading outages.
- Plans should be made to minimize the size and duration of outages resulting from operating error or from the loss of multiple facilities such as a four-unit generating station, all the circuits on a transmission line right of way, or a major load.

The security methods provide only a qualitative measure of reliability; they do not provide quantitative yardsticks of the magnitude, frequency, and duration of interruptions. The methods that have been proposed for quantitative reliability evaluation are based only on the steady-state aspects (see Table 4.1). Because a transmission network has both "series" and "parallel" connections of components, determining the cause of an interruption in service depends on the identification of a particular component. Therefore, security methods must consider all possible combinations of component outages. The proposed methods include the following basic steps:

- Select an operating state of the bulk power system that involves the outage of one or more elements.
- Dispatch power to satisfy the load.
- Determine the power flow on each transmission link.
- Check for overloads and low-voltage conditions.
- If a link is overloaded, it is assumed that the outage will cause a failure.
- Calculate the amount by which the load has to be reduced at various load points.

By repeating this procedure for each state of the system, and analysing the data on the frequency and

duration characteristics of each state, it is possible to obtain reliability indices at specific system load points, in stated system areas, or for the entire system. But the number of possible states for a practical system may be extremely large (2^N for a system with N components). In order to keep computational requirements within reasonable limits, procedures must be devised for selective evaluation of system states that will give results of acceptable accuracy. These procedures include "Monte Carlo" simulation, in which only a randomly selected sample of states is examined, and the ranking of outage states of the system according to their probability of occurrence and their adverse impact on the system.

To amass sufficient statistical data to provide a consistent basis for probabilistic estimates of the failure rates and types of failure of the great many components that are involved is a challenging task. To evaluate reliability under dynamic operating conditions, transmission network analysis must deal with system stability under specified fault, or short-circuit, conditions. The models must therefore simulate realistic responses, such as cascading, the activation of the protection apparatus, and a load curtailment as dictated by various operating policies. Attempts must be made to include the effects of planned outages of generating units and transmission lines, of daily, weekly, and seasonal variation of loads at different points, and of multiple outages involving some common cause. Integrating these several model capabilities into realistic and practical procedures that give a quantitative measure of reliability is a challenge to the electricity utility industry, and considerable attention is being devoted to it.

Ontario Hydro is involved in a computer programme called PCAP, which has been developed jointly by Power Technologies Inc. and the NPCC in a move to advance the state of the art in reliability analysis. PCAP embodies the basic ideas outlined in the preceding discussion. An important feature of the programme is its ability to select automatically and subsequently test outage states that are likely to result in system failure. Thus, the number of cases that must be analysed is greatly reduced. Although PCAP determines the adequacy of the bulk power supply system under static conditions, NPCC hopes that, through this programme, significant system contingencies that may escape detection with common planning methods may eventually be foreseen.

Distribution Reliability Evaluation

In the distribution sector, a failure is defined simply as an interruption of customer service due to an outage in the distribution system. Probability techniques are available to evaluate distribution reliability but their application has not been as extensive as in the generation sector. Moreover, the availability of data on the outage rates of distribution equipment has been limited.

The traditional way of evaluating reliability in the distribution system has been to measure the reliability actually experienced by various customers and to improve it, where needed, with better equipment, better maintenance practices, or system reinforcements. Utilities maintain statistical records of the outage data on equipment, by the type of equipment, its manufacturer, and its age. These data serve as a guide for future purchases and help to determine the best time for retiring each piece of equipment. The utilities often employ quantitative methods of reliability analysis when they wish to modify their existing designs, for example, when there is a move to a higher primary distribution voltage. Such a move would increase the number of customers that could be served per circuit, but at the same time it might increase the likelihood of power interruption because of the need to use longer feeders. Reliability analysis can help ensure that the move to a higher voltage will not reduce the reliability of supply. Another example of a situation in which modifications in existing designs are required is the conversion of overhead distribution to underground.

In general, the outage of a single component in the distribution system will cause an interruption of supply to some customers. Because of this, the techniques for evaluating distribution reliability are geared to single-component failures. The duration of an interruption caused by such a failure depends on many factors. A piece of equipment may be permanently damaged and have to be repaired or replaced. It may be rendered inoperative temporarily by some external cause such as lightning, and the interruption of supply will then be momentary if the protective devices work properly. But if a protective device such as a circuit-breaker fails to re-close after a lightning strike, the interruption may be prolonged.

In Ontario, most of the distribution systems are owned and operated by public utility commissions (PUCs). The PUCs do not favour a reduction in the existing distribution reliability standards. Their main argument is that they are the principal targets for complaints by customers in the event of a supply interruption, regardless of whether the outage is in the distribution system or the bulk power

system. It is natural for the commissioners, managers, and staff of the PUCs to want to avoid public criticism. Many customers are served from the distribution centres by a single feeder, a mode of service with minimal reliability. Only customers whose cost of interruptions is very high are provided with multiple feeders from alternate supply points. Certain industries, hospitals, large shopping centres, commercial buildings, and large schools fall into this category.

Evaluation of the Reliability of Supply to the Customer

As was stated earlier, practical methods do not exist at present for evaluating reliability of supply to customers on the basis of a quantitative evaluation of the reliability of the three subsystems of the total power system. Attempts are being made by the power industry to integrate the models of generation reliability and bulk power transmission reliability. The PCAP programme of Ontario Hydro is an example. Depending on the success and acceptance of such methods, distribution reliability models may be incorporated with them to provide measures of reliability to the customers.

Reliability of supply to the customers may be measured on the basis of past performance, by recording the number of customers interrupted, the frequencies and durations of the interruptions, and the amounts of load not supplied as a result of the interruptions. Data of this type may be used to predict future performance. The recording of past performance also provides a measure of the relative past contributions of the major subsystems - generation, bulk power transmission, and distribution - to reliability of supply. Data of this type indicate that, in Ontario, loss of supply at the customer level has occurred most frequently as a result of failures within the distribution system. Failures in the transmission system appear to have had a relatively minor effect on reliability of supply to the customer, and generation failures appear to have had little or no effect. Ontario Hydro customers have not suffered an interruption of supply as the result of generation shortfall for many years. During the Commission's public information hearings it was pointed out that this is true of the last 25 years or so. There have been occasions, however, when Ontario Hydro had to make emergency purchases of power from the U.S. due to generation deficiency. This is particularly true of the late 1960s, when Hydro had installed generation reserves of less than 10 per cent. In December 1976, some industrial interruptible loads were cut because of a combination of several severe contingencies: abnormally cold weather pushed the peak demand to unusually high levels; power was locked in at the Lennox Generating Station due to transmission bottlenecks; and several units of the Nanticoke Generating Station were forced out of service. The severity of the situation was reduced considerably by emergency purchases from neighbouring systems, proving beyond doubt the benefits of interconnections.

An indication of the reliability of Ontario Hydro's bulk power supply system (generation and transmission) can be obtained by considering the average annual number of interruptions and the average total duration of interruptions experienced per year at each delivery point of the bulk power system. The data for the period 1970-75 indicate that, on the average, each delivery point suffered 1.85 interruptions per year and the total duration of the interruptions at each delivery point was 21.3 minutes per year. Translated into an index of the availability of supply, this gives a value of 99.996 per cent. These figures may be compared with the data on the supply of electricity to some of Ontario Hydro's 700,000 or so rural customers. Data from rural customers in nine areas of the province indicate that each customer experienced, on the average, 2.88 interruptions per year, with a total duration of 182 minutes per year, giving an availability index of 99.9654 per cent. Thus, in terms of the duration of interruptions, the contribution of the failures in the bulk power system is small. The frequency of interruptions cannot be compared properly because the figure for rural customers does not include brief interruptions lasting less than a minute.

The Costs and Benefits of Reliability

Since reliability is an important characteristic of an electric power system, the question of how much reliability, that is, how much generation reserve and how many transmission lines or other system elements should be installed, is central in the designing of a system. In the operation of a power system, the transmission lines are usually not loaded to their maximum physical capability. Thus, when a generating unit has to be taken out of service due to an outage, power can generally be moved from areas of surplus generation to make up the deficiency. To a certain extent, then, it is economically more efficient if an electricity utility has reserve generating capacity in some parts of its system than it is if each customer has to either buy his own back-up or storage device or suffer due to interruptions of supply. For planning purposes, the question is how to determine the point at which the cost of extra

generating capacity (and hence reliability) created by the utility exceeds the costs incurred by the customer as a result of power interruptions. The cost to the utility may be computed from system planning studies, but the costs incurred by customers are extremely difficult to estimate. Some customers, such as an average residential customer, might not be greatly inconvenienced in good weather by a loss of power for one hour. Others, such as a continuous process textile plant, might be severely affected by a shut-down of only a few seconds. Thus, the costs of an outage will depend significantly on the time of year, the type of customer affected, and the magnitude and duration of the outage.

Until recently, the electricity utilities in North America made no direct attempt to balance these costs. However, there are a number of cases of increased reliability being purchased by a customer. For example, a hospital may have stand-by generating equipment for back-up, and a particularly sensitive industrial plant may have an extra transmission line in case of a line outage. Historically, in North America, new fossil-fuelled generating units have been more efficient than the old ones, and so have had lower fuel costs per unit of energy produced. Moreover, the economies of scale in the new, larger plants have meant less capital cost per unit of capacity. Thus, with a growing demand for energy, the incremental cost of capacity at the peak period was below the average cost and so the average cost was dropping over the years. Under these circumstances, an approximate measure of the past reliability that had been acceptable to customers was used for planning purposes.

Recent approaches to choosing an appropriate level of reliability for electric power systems attempt to balance the benefits accruing to the customers and to society from reliability with the costs incurred by the utility (which are, of course, passed on to the customer). The benefits to the customer and to society are usually taken to be costs that can be avoided because of the existence of redundant units. The net benefits are then the benefits accruing to the customers and to society, minus the costs incurred by the utility in providing a given level of reliability. The "best" (or optimal) level of reliability is that which maximizes the net benefits. In practice, utilities often use another, equivalent, formulation in which the optimum reliability level is that which minimizes the sum of the direct costs incurred by the customer and the indirect costs incurred by society at a given level of reliability and the costs incurred by the utility in maintaining that level of reliability. Moreover, provided that the cost functions of the utility and the customers are convex, the formulation may be further simplified to one of equating the incremental cost to the utility of ensuring reliability with the incremental costs incurred by the customers and by society as a result of interruptions.

Presentations to the Commission by Ontario Hydro indicate that Hydro is improving its criteria for selecting reliability levels. The new methodology, which has been described in Ontario Hydro's System Expansion Program Reassessment (SEPR) study, balances the estimates of the costs incurred by customers and society as a result of outages with the costs incurred by the utility in achieving a given level of reliability.[4] For several planned reserve margins, it basically combines the expected frequency and duration of outages of different magnitudes with the results of some user surveys of the costs to customers of each type of outage. Then these results are combined with an econometric model to produce estimates of the total economic cost of interruptions. The cost of a given measure of reliability (SEPR uses generation reserve margin) is the sum of the direct costs to the customer of interruptions caused by outages, the indirect costs to the province (such as a reduction in the gross provincial product), and the costs to the utility for generation, transmission, and distribution. These costs are calculated annually and the sum of their present value is defined as the total economic costs (to the society) associated with a given set of assumptions concerning the system expansion programme and the demand. In this work, most analyses assume that all generation and load are located at a single point, so transmission and distribution are studied in much less detail.

This new approach, balancing the costs of outages incurred directly by the customer with the costs to a utility of maintaining a given reliability level is a significant improvement on the loss-of-load-probability (LOLP) method, which used a target level based on historical considerations. For several years, Ontario Hydro has been computing the frequency and duration of generation system outages, but the F&D results were used to assess the performance of the system, not to design it. The application of the F&D technique to the design of the system necessitated three further steps. First, the accuracy and detail of the F&D computer programme were improved. Second, consumer surveys were undertaken to supply some estimate of the customers' perceptions of the costs incurred during outages of various durations (e.g., very short, one hour, two hours, etc.). Third, a methodology was developed to combine the F&D results, the historical transmission and distribution outage experience, and the consumer survey results into estimates of the direct costs of unreliability suffered by Ontario Hydro customers and the

indirect economic costs suffered by the province. These costs were then combined with Ontario Hydro's expenditures to provide an estimate of the "total economic cost". Then the minimum total economic cost was used as the design criterion for system reliability.

We will consider, first, how the reliability of the total system is estimated in the SEPR study. Then we will examine how the customer losses were estimated. Finally we will see how the total costs to the system were obtained, so as to arrive at a minimum cost level of reliability.

The reliability of the generation system is evaluated by Ontario Hydro's F&D programme, as described earlier. The programme computes the expected frequency and duration of generation outages, and the expected amount of energy not supplied on demand during the year because of generation deficiency. These indices are used as measures of generation reliability. Since a transmission system's reliability is, in practice, much more complex and hence more difficult to assess than a generation system's, it is assumed in the study that the transmission system's historical performance will continue into the future. For the "reliability balance" calculations, it is assumed that the energy unsupplied due to transmission failures will remain a constant fraction of peak demand, and that the fraction of outages of a given duration will remain constant as the system grows. The effect of these two assumptions is that the number of interruptions experienced by Ontario Hydro's "average" customer would remain unchanged. For the distribution system, a similar approach is used. Historical values both for energy unsupplied as a fraction of peak demand and for the fraction of interruptions of a given duration are assumed to be constant into the future. Thus, the "average" customer would continue to experience one or two interruptions per year.

The costs of unreliability are considered to be of two types: direct costs to customers and indirect costs incurred by other elements of society. The direct costs incurred by each customer are affected by the frequency of outages, the duration of each outage, the magnitude of each outage, the amount of advance notice, and the time of the day, week, or year when each outage occurs. However, the reliability indices used by Ontario Hydro are the mean (or average) values of frequency, duration, and unsupplied energy. Thus, of the factors that affect customer costs, only the mean values of the first two (frequency and duration) are computed as reliability indices. The mean value of energy not supplied may be determined from the frequency, duration, and magnitude of generation deficiencies. To estimate the direct costs of unreliability, Ontario Hydro's customers are divided into four groups: large users, other manufacturing, commercial, and residential and farm. These groups are associated with the existing rate structure. The direct (or out-of-pocket) costs for the customers in the first, second, and fourth groups are based on Ontario Hydro surveys asking for estimates of direct losses as a result of interruptions of different durations that occur without warning. The questions asked required a considerable effort on the consumer's part to provide reasonable numerical answers. So, clearly, the results should be taken as indicators rather than as highly precise values. Nevertheless, they give some insight into the magnitude of the cost of an outage in relation to its duration. No survey was available for the commercial group, and so its costs were estimated on the basis that the losses are proportional to wages and salaries in the commercial sector of Ontario's economy and to the amount of energy not supplied on demand. It was also assumed that the costs of interruptions for the farm group are the same as those for
Fig. 4.4: p. 55 the residential group. The results of the surveys are summarized in Figure 4.4.

The next step is to combine the loss data for each customer class, to make an estimate of the total cost of a given level of unreliability. First, the losses caused by the generating system are estimated. This is done by assuming that all load-shedding is imposed on customers one hour at a time and that there is no discrimination among customers, that is, that each customer group experiences an equal number of one-hour load cuts. The direct losses caused by generation unreliability are calculated by combining the four customer loss functions of Figure 4.4 with the estimates of load-shedding produced by the F&D computation.

It is important to note that for a given planned reliability level, the uncertainty in load forecast and generation in-service dates means a considerable variation in reliability level that may be achieved in a given future year. Since the cost of outages escalates quickly as the shortfalls in generation increase, the costs of outage computed as if the planned reliability level had been achieved are not adequate indicators of the real impact. Thus, for a given planned reliability level, it is the expected value of the cost of outages (that is, the mean of the costs over all probable reliability levels) that is computed, not the cost corresponding to the expected level of reliability.

Customers' direct losses due to transmission system unreliability were computed by assuming that each customer class had equal exposure to interruptions and that each would experience its share of

long and short interruptions. The customer losses attributable to the distribution system are computed by assuming that all have equal exposure to interruptions (except those connected directly to the transmission system).

Table 4.3 shows the direct losses by customer class attributable to the generation, transmission, and distribution subsystems. Note that, among the classes of customers, "other manufacturing" has the largest share of total losses. Moreover, distribution accounts for more direct costs of interruption than transmission. Table 4.3 also illustrates the contrast between the share of Ontario's electricity that is consumed by each customer class and the computed share of total direct losses accruing to each class.

Table 4.3 Projected Direct Customer Losses in 1990 – SEPR Study[a]

		Average direct customer losses (millions of 1990 dollars)						Share of total direct losses (%)	
		Generation		Transmission	Distribution	Total			
Customer class	Share of electricity demand (%)	23% reserve	28% reserve			23% reserve	28% reserve	23% reserve	28% reserve
Large users	31	12.5	c	3.2	2.5[b]	18.2	5.7	28	18
Other manufacturing	19	12.5	c	2.9	13.1	28.5	16	43	52
Commercial	17	9.3	c	1.6	7.3	18.2	8.9	28	29
Residential and farm	33	0.3	c	0.1	0.2	0.6	0.3	1	1
Total	100	34.6	0.08	7.8	23.1	65.5	30.9	100	100

Notes:

a) Projections are for a 5.5 per cent average annual rate of load growth to the year 2000.

b) Many large users are supplied directly from the bulk power transmission system.

c) Relatively small.

Sources: RCEPP and Ontario Hydro, "System Expansion Program Reassessment Study", Fifth Interim Report, November 1978.

The indirect costs of interruptions are taken to be the reduction in the gross provincial expenditure (GPE), over and above the direct costs in the industrial and commercial sectors. The direct losses imposed on these customers are assumed to cause a reduction in profits, and 60 per cent of this reduction in profits is taken as the reduced investment by these two sectors. Through an econometric model, the reduction in investment is translated into a reduction in the GPE. The difference between these two is taken as the indirect cost of interruptions to supply. The total economic cost of a given level of reliability is then the sum of the direct costs incurred by the residential and farm customers, 40 per cent of the direct costs incurred by the industrial and commercial customers, and the reduction in GPE that is associated with the reduced investment by the industrial and commercial sectors.

As shown in Figure 4.5, the total economic costs attributed to a given planned reserve margin are the sum of the present value (over the study period) of Ontario Hydro's expenditures for system expansion and the total economic costs of interruptions. Figure 4.5 shows that the effective target generation reserve corresponding to minimum total economic cost considerations is about 5 per cent lower than the reserve determined by the traditional LOLP criterion of 1/2,400. The figure also shows that the cost of interruptions drops rapidly as the reserve margin increases and is virtually nonexistent at the "optimum" reserve level. The choice of "optimum" reserve is influenced by many factors which have not been included in the computations of the SEPR study. Therefore, results such as those presented in Figure 4.5 should be interpreted as indicative rather than definitive. Fig. 4.5: p. 56

The studies that try to balance the costs to the customer with the costs to Ontario Hydro are an important improvement in the effort to determine a justifiable level of system reliability. However, there are several aspects of the SEPR approach that require further investigation. First, the customer surveys ask for a single estimate for each category of cost and duration. These estimates are inherently uncertain, and it is suggested that the respondents should be allowed to respond with a range of costs. Then some estimate of the range of uncertainties might be given on a graph similar to Figure 4.5. Second, to develop scenarios of generation expansion, the study assumes a reserve margin whose value would be constant over the planning period. A constant reserve margin has not been the planning criterion in the last few years; a better measure, the LOLP, has been used. Moreover, the system's planned reserve margin has not been constant in the past. With the proportion of hydraulic and nuclear plants in the system due to change significantly in the future, the reserve margin should not be held constant. We feel that a balance of customer and utility costs on a smoothed annual basis, and not a constant reserve margin with the lowest present value of costs over the whole study period, should be a planning objective. For example, as shown in Figure 4.6, the annual energy not supplied at reserve margins of 17 per Fig. 4.6: p. 57

cent and 22 per cent is growing much faster than the system peak. Thus, a present value calculation assuming constant reserve margin may conceal the fact that the costs of interruption are escalating quickly, and it may not indicate that the reserve margin should perhaps be increased as time progresses, rather than being held constant. Third, the extra costs incurred by the utility to increase the reserve margin from the base case are computed by adding 800 MW coal-fired units. Clearly, extra capacity can also be obtained by advancing the nuclear programme (especially in the case of low nuclear scenarios) and/or by adding some combustion turbine units or smaller coal-fired units. Since the slope of the "expenditures" line in Figure 4.5 significantly affects the balance point, the effects of using other types of plants to increase capacity should be explored. Finally, as noted in the SEPR study, further work needs to be done to investigate transmission and distribution reliability in more detail.

Summary and Conclusions

The assessment of the reliability of an electric power system is a very complex and difficult problem. Ontario Hydro, like many North American utilities, has traditionally used the probability-based LOLP approach for evaluating the reliability of its generation plans, and security criteria for planning bulk power transmission. The planned generation reserve margins have been in the order of 30 per cent to correspond to an LOLP of 1/2,400. Due to the inability of the LOLP method to provide measures of reliability in terms of the frequency, duration, and magnitude of outages, Ontario Hydro has developed a generation reliability programme based on the frequency-and-duration-of-outages method. The F&D technique is considered to be far superior to the LOLP method.

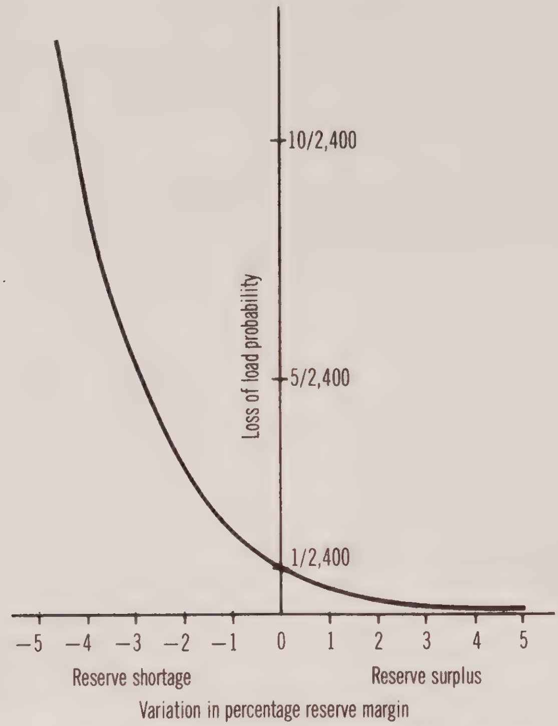
While methods of evaluating generation reliability have received most of the attention of utility planners, Ontario Hydro and its neighbours are active in developing practical schemes for the quantitative evaluation of transmission reliability. These schemes are necessarily complex, and it will be some time before they find widespread use among electricity utilities.

In Ontario, the contribution of failures in the bulk power system to interruptions of supply to customers has been small. Most interruptions occur as a result of failures in the distribution system. For example, data from Ontario Hydro's rural customers show that they suffered interruptions with a total average duration of 182 minutes per year, whereas the duration of supply interruptions at each bulk power delivery point was only 21 minutes per year.

Ontario Hydro has undertaken studies to assess reliability by balancing its costs and benefits to the consumer. A measure of the benefits of reliability, which are extremely difficult to estimate, was obtained by canvassing customers to get their perception of losses due to supply interruptions. Further work needs to be done, but the results of these studies already indicate that the planned generation reserve margins could be reduced by a few percentage points. As a result of its studies, Ontario Hydro has reduced its planning reserve from approximately 30 per cent to about 25 per cent. The new target reserve is based on a reduced generation reliability criterion of 10 system minutes of unsupplied energy per year, after taking due account of a 2.7 per cent load reduction by voltage reductions, and of some help (500-700 MW) from interconnections.

Studies such as these constitute an important improvement in the efforts to determine a justifiable level of system reliability. They indicate that Ontario Hydro is among the pioneers in advancing the state of the art of reliability assessment. It must be noted, however, that Ontario Hydro has not attempted to evaluate, from a reliability viewpoint, decentralized system scenarios based on the concept of "local energy centres". A factor that may be hindering this attempt is the unavailability of practical techniques for evaluating overall system reliability.

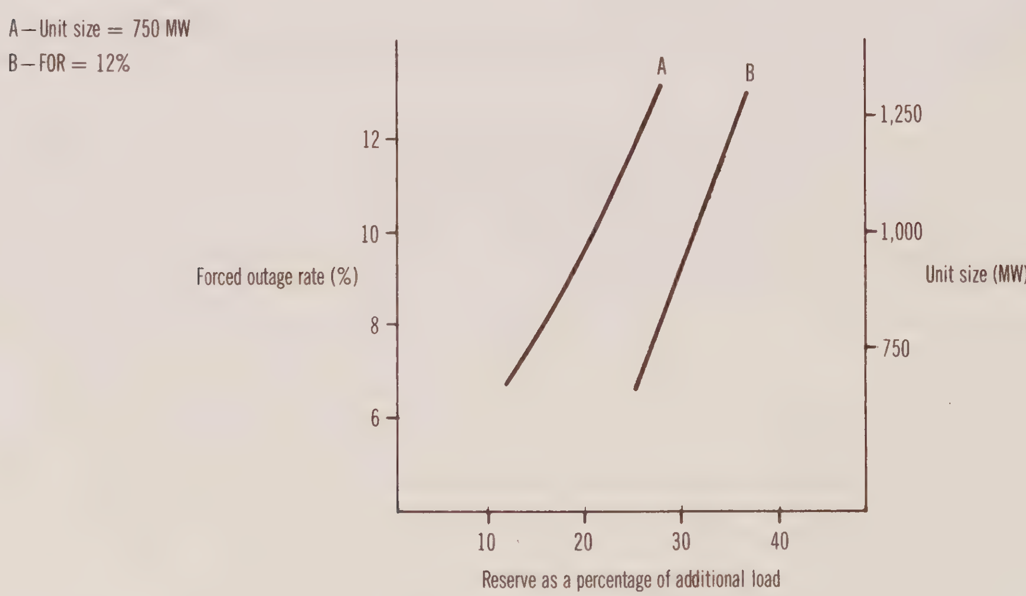
Figure 4.1 Variation in Loss of Load Probability with a Change in Reserve Margin (Ontario Hydro East System)



Note: Based on data from a proposed 20-year expansion of Ontario Hydro's East System under long-range forecasts LRF 48 and LRF 48A. The reference value for reserve variation corresponds to an LOLP of 1/2,400.

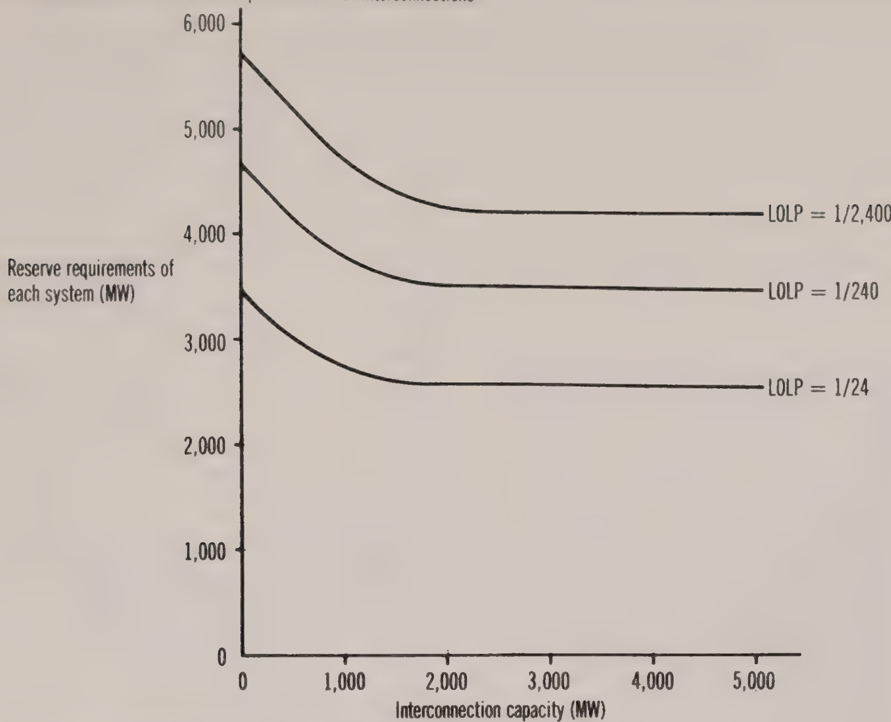
Sources: RCEPP and Ontario Hydro.

Figure 4.2 Variation in Incremental Reserve Margin with a Change in the Forced Outage Rate and Unit Size



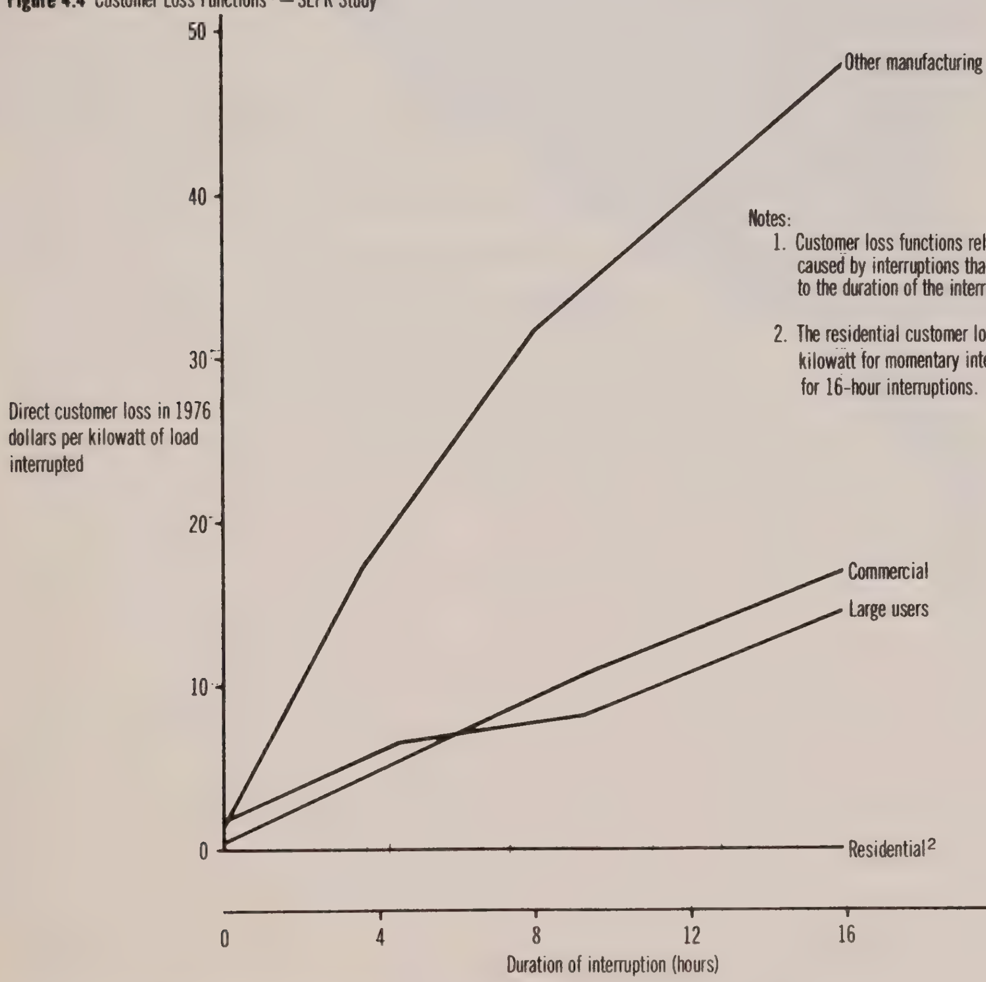
Source: "Generation Planning Processes", Ontario Hydro submission to RCEPP, May 1976, Exhibit 21.

Figure 4.3 Possible Reduction in Reserve Requirements with Interconnections



Source: "Reliability", Ontario Hydro submission to RCEPP, May 1976, Exhibit 20.

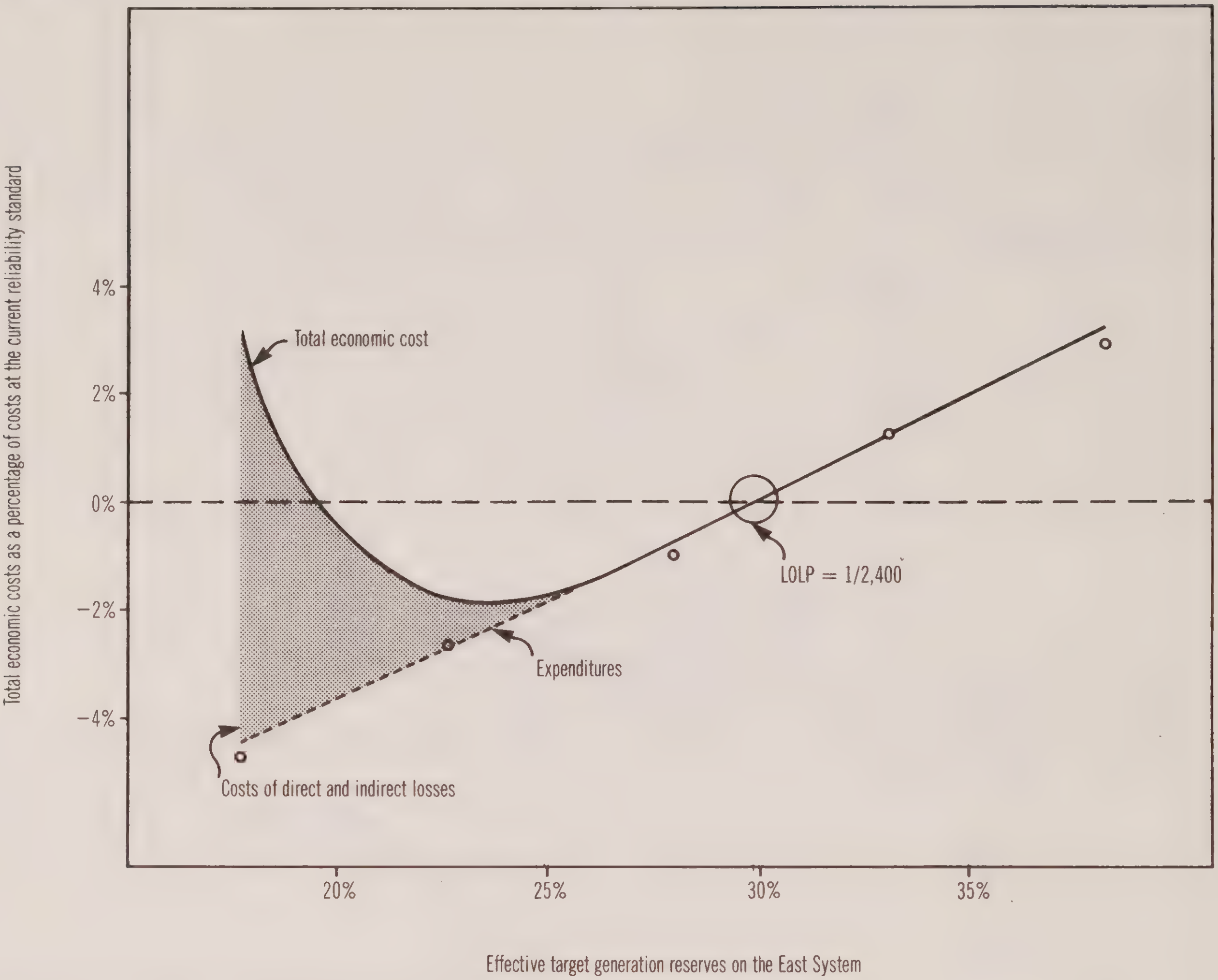
Figure 4.4 Customer Loss Functions[1] — SEPR Study



Notes:
1. Customer loss functions relate customers' direct financial losses caused by interruptions that occur without warning, to the duration of the interruptions.
2. The residential customer loss function rises from 0.03 dollars per kilowatt for momentary interruptions to 0.12 dollars per kilowatt for 16-hour interruptions.

Source: "System Expansion Program Reassessment Study", Ontario Hydro, Fifth Interim Report, November 1978.

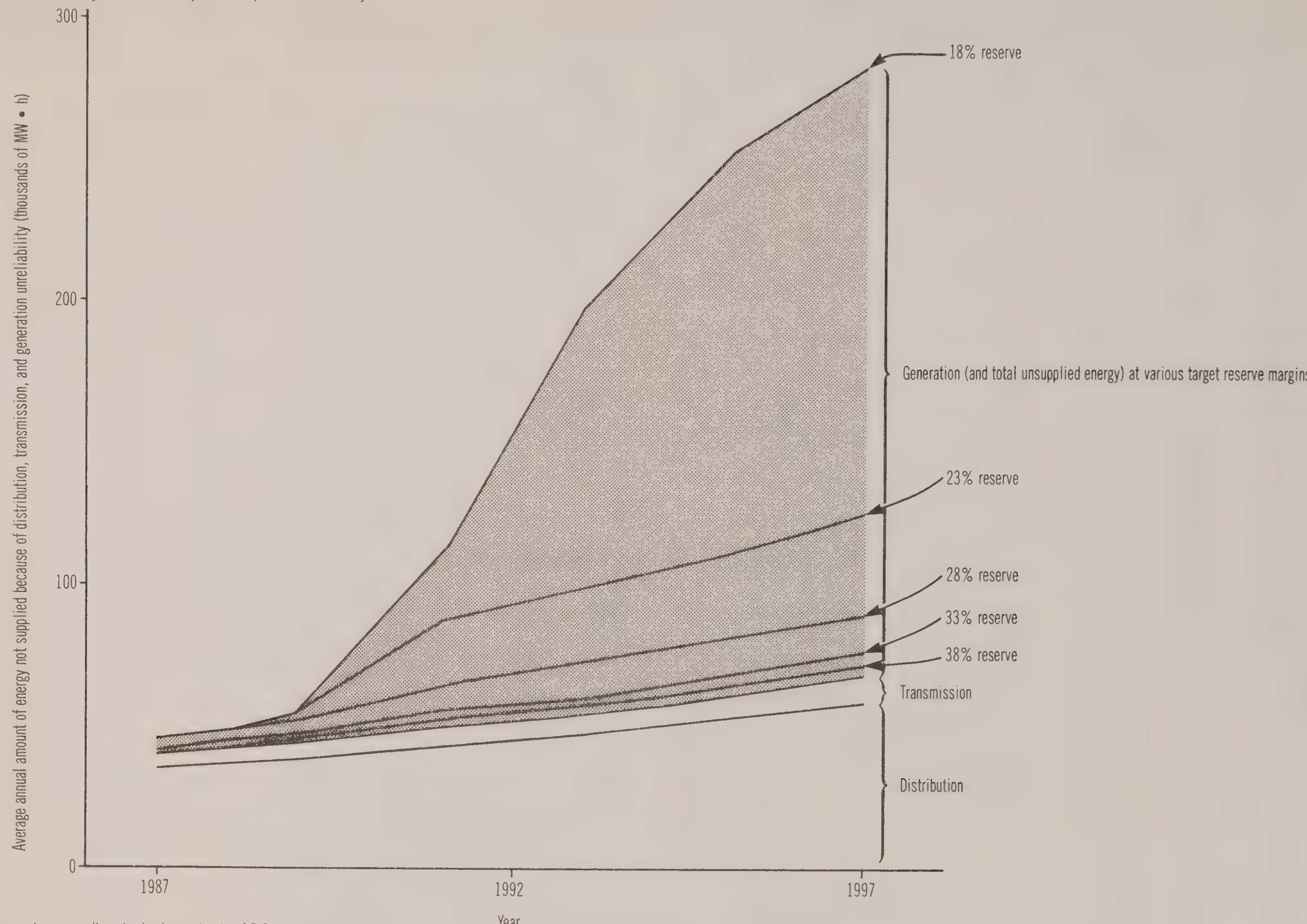
Figure. 4.5 Variation of Total Economic Costs with the Target Generation Reserve — SEPR Study



Note: Based on present value of costs for 1985-1997 at a 15 per cent discount rate and a 5.5 per cent annual growth in load.

Source: "System Expansion Program Reassessment Study", Ontario Hydro, Fifth Interim Report, November 1978.

Figure. 4.6 Total System Unreliability on the Ontario Hydro East System — SEPR Study



Note: Estimates are for a system expanding at a load growth rate of 5.5 per cent per year.

Source: "System Expansion Program Reassessment Study", Ontario Hydro, Fifth Interim Report, November 1978.

CHAPTER FIVE

Interconnections with Other Systems

Ontario Hydro's province-wide power transmission system is interconnected with those of electricity utility systems in neighbouring provinces and states, and these systems are, in turn, similarly interconnected with their neighbours.

The gradual evolution from small isolated systems in the early years of the industry to today's interdependent systems reflects the growing recognition that reliability of service can be improved and cost of service reduced through interconnection and co-ordination.

Co-ordination of the planning and operation of electricity supplies on interconnected systems offers a variety of benefits. Hydroelectric resources may be utilized more fully if developed to serve regional rather than local needs. Nuclear or fossil-fuelled generating stations may be located at advantageous sites, and concentrated in large centres so as to realize economies of scale. The amount of generating capacity needed by each interconnected system may be reduced, because the peak demands of the participating utilities vary in size and timing – the so-called load diversity (see Figure 2.1). Requirements for reserve generation may be reduced by special arrangements for mutual assistance in emergencies. Responsiveness to unanticipated shortfalls or overruns of supply and demand is improved. The reliability of the bulk power system may be enhanced and service standards improved by the co-ordination of spinning reserves, system frequency and voltage controls, operating schedules, and maintenance programmes. Substantial reductions in operating costs may be realized through co-ordinated operation of all the production facilities available to the interconnected systems. The capability for dealing with extreme contingencies and disasters is improved. Financial burdens may be alleviated through the sharing of risks as well as of benefits. The move towards fuller utilization of renewable primary energy resources may be accelerated, and dependence on scarce and dwindling supplies reduced.

On the other hand, the establishment of an interconnection can be costly, particularly if it is of substantial length. There must be assurance of interconnection transactions of large and sustained value to warrant the investment. Other costs may be incurred, including those resulting from the environmental impact of the interconnection and of the related power plant construction and operation. And the various participants may find it difficult to reach agreement on the benefits and costs and how they should be allocated among the interests affected.

The use of interconnections also raises complex issues in respect of public policy. Consider, for example, the transmission lines across the Niagara River that interconnect the Ontario Hydro and Niagara Mohawk systems. The power that has been transferred over these lines has provided substantial economic benefits to both parties. However, the existence of this interconnection was a major factor contributing to the massive black-out of 1965, in which almost the entire Atlantic seaboard was plunged into darkness. That the utilization of such interconnections raises important questions of public policy is evidenced by the fact that transactions concerning them may require the approval, not only of the utilities concerned, but also of the provincial, state, and federal governments and their agencies.

Electricity Trade with Neighbouring Provinces and States

Existing Interconnections

Ontario Hydro has high-voltage interconnections with electricity utilities in neighbouring provinces and states, as follows:

Manitoba Hydro – one 115 kV and two 230 kV lines near Kenora, providing a nominal interchange capability of 475 megavolt amperes (MVA).

Hydro-Québec – eight 115 kV and four 230 kV lines that cross the Ontario-Quebec border at various points (Beauharnois, Masson, Ottawa, Chats Falls, New Liskeard, Kirkland Lake), providing a nominal interchange capability of 2,735 MVA.

Detroit Edison Co. – two 230 kV and two 345 kV lines at Sarnia and Windsor, providing a nominal interchange capability of 2,855 MVA.

Power Authority of the State of New York (PASNY) – two 230 kV lines at Cornwall, providing a nominal interchange capability of 720 MVA.

Niagara Mohawk Power Corporation and PASNY – two 230 kV lines at Niagara, providing a nominal interchange capability of 720 MVA.

The actual transfer capability depends upon overall configurations of load, and generation and transmission capacity in the vicinity of the interconnection, and is usually well below the nominal capacity. It also varies with the direction of power flow. Ontario Hydro also has interconnections with other power systems within Ontario, which will be discussed later, and it deals, as circumstances warrant, with other utilities in the U.S. with which it is not directly connected, by arranging with the intervening utility systems to "wheel" the power. Through these arrangements, Hydro has access to a large and dynamic wholesale market.

The Volume of Transactions

Table 5.1 shows Ontario's annual electricity trade with its neighbours (1968-77) in billions of kilowatt hours. These are totals for the province but comprise mainly transactions made by Ontario Hydro. Electricity trade was vigorous throughout the period. In recent years, total trade (exports plus imports) has approached 25 per cent of the total electricity made available in Ontario (production in Ontario plus imports less exports). Imports exceeded exports and came mainly from Quebec; exports went mainly to the United States.

Table 5.1 Ontario – Interprovincial and International Electricity Transfers

Volume of trade (TW·h)	68	69	70	71	72	73	74	75	76	77
Quebec										
Imported by Ontario	4.8	4.7	6.3	5.9	8.1	9.6	10.8	11.4	11.7	10.7
Exported by Ontario	0.2	0.1	0.2	0.3	0.2	0.1	0.2	0.3	0.3	0.3
Manitoba										
Imported by Ontario	0.1	0	0.2	0.3	0.5	0.8	1.6	1.7	1.6	0.9
Exported by Ontario	0.1	0	0.8	0	0	0	0	0	0.1	0.1
U.S.A.										
Imported by Ontario	2.6	2.2	2.9	2.6	1.7	1.6	1.8	2.7	2.1	1.2
Exported by Ontario	2.5	2.9	3.6	4.1	6.1	7.6	7.9	4.8	6.2	9.6
Totals										
Imported by Ontario	7.5	6.9	9.4	8.8	10.3	12.0	14.2	15.8	15.4	12.8
Exported by Ontario	2.8	3.0	4.6	4.4	6.3	7.7	8.1	5.1	6.6	10.0
Total imports and exports	10.3	9.9	14.0	13.2	16.6	19.7	22.3	20.9	22.0	22.8
Total available in the province										
(production plus imports-exports)	61.1	64.8	69.5	73.0	79.1	84.3	88.8	89.2	96.1	98.6
Percentage of total available										
Imported by Ontario	12	11	14	12	13	14	16	18	16	13
Exported by Ontario	5	5	7	6	8	9	9	6	7	10
Total imports and exports	17	16	21	18	21	23	25	24	23	23
Cost and revenue										
Imports by Ontario										
Cost of imports ($million)	15.1	14.3	28.6	29.4	25.7	39.5	57.3	64.7	66.5	65.1
Unit cost (cents/kW·h)	0.20	0.21	0.30	0.33	0.25	0.33	0.40	0.41	0.43	0.51
Exports by Ontario										
Revenues from exports ($million)	4.4	9.6	22.9	28.4	41.0	72.4	105.2	48.0	94.9	216.5
Unit price (cents/kW·h)	0.16	0.32	0.50	0.65	0.65	0.94	1.30	0.94	1.44	2.17

Source: "Total Transfers by Ontario Utilities and Industrial Establishments", Statistics Canada 51-202, vol. 2.

Table 5.1 also shows the cost of imports and the revenues from exports. The costs of imports exceeded the revenues from exports in the late 1960s and early 1970s, but the situation has been reversed since then. The unit price of exports has, in fact, always been considerably higher than the unit cost of imports, except in 1968. While the unit cost of imports escalated at a relatively moderate rate from 0.2 to 0.5 cents/kW·h, the unit price of exports soared from 0.2 to 2.2 cents/kW·h.

Ontario Hydro's imports have been mainly in the form of purchases of firm hydroelectric energy from Quebec, and to a lesser extent from Manitoba, on a long-term basis and at a fixed price that is low by present standards. Its exports have been mainly through short-term opportunity sales of non-firm energy from coal-fired generation that is temporarily surplus to its own needs, to American utilities

that would otherwise have to meet their requirements from higher-priced oil-fired generation. The deliveries of firm hydroelectric energy from Quebec ended in 1977, however, and Ontario Hydro's transactions with neighbouring states and provinces are now mainly for the purchase and sale of non-firm, or "secondary", energy.

Types of Interconnection Transactions

Ontario Hydro has interconnection agreements that prescribe the ground rules under which it arranges short-term transactions with its neighbours. These transactions are of the following types:

Short-Term Capacity. Power and associated energy provided for a period of from one week to about six months to supplement the peak generating capability of the receiving party during periods of prolonged capacity deficiency.

Daily Capacity. Power and associated energy provided on a day-to-day basis to supplement the peak generating capability of the receiving party at a time of temporary capacity deficiency.

Spinning Reserve. Excess generating capacity that is held ready by one party for use by another on a few minutes' notice.

Supplemental Energy. Energy provided during off-peak hours to supplement storages (fossil-fuel or hydraulic) of the receiving party.

Economy Energy. Energy delivered in order to effect a saving in the cost of generation when the receiving party has adequate generating capability available to carry its own load.

Tertiary Energy. Scheduled deliveries of energy that cannot be classified under other categories.

Inadvertent Energy. Non-scheduled energy.

Wheeling Service. The transportation of electric energy on a scheduled basis through one party's system at the request of the other party.

Price schedules for these transactions are reviewed periodically. Economy energy is usually priced on a split-the-savings basis, that is, mid way between the supplier's incremental cost of fuel, incidental materials, and labour and the buyer's "decremental cost", or savings, in reduced fuel and incidental costs.

A typical capacity charge is $100 per megawatt day, subject to periodic revision. The energy associated with a capacity sale may be sold at the economy energy rate or at cost plus 10 per cent, whichever is higher. It is advantageous to the seller to collect both a capacity charge and an energy charge, and most of Ontario Hydro's sales have been of this nature.

The Outlook for Electricity Trade

Like other aspects of the energy sector in general and the electricity supply industry in particular, interconnection practices are today receiving close scrutiny from numerous diverse interests, and the course of future development is in doubt.

Most transactions with U.S. utilities have been short-term opportunity sales from coal-fired generation that has been temporarily surplus to domestic needs. Sales have been large and highly profitable. The selling price has been substantially more than either the incremental cost of production or the wholesale rate to domestic customers.

Ontario Hydro, at present, imports most of the coal it needs from the United States. A portion of these imports is used for the power exports to the U.S., and some experts maintain that this two-way trade helps to ensure the availability of coal from the U.S. Others object to these transactions on the grounds that they aggravate atmospheric pollution in Ontario. However, in approving such exports, the National Energy Board has expressed satisfaction that the revenues adequately cover all costs incurred, including social costs.

Ontario Hydro is faced with considerable surplus in generating capacity, because demand has not grown as much as expected, and this surplus is expected to continue until the early 1990s. The surplus power will peak at about 4,000 MW in the early 1980s. Hydro is striving to make profitable sales from this surplus and has had some success – six-month contracts ending in December 1979 were signed with the Niagara Mohawk Power Corporation (250 MW) and General Public Utilities (200 MW).[1]

It is obviously not possible to forecast such opportunity sales beyond the short term with any confidence.

Ontario Hydro is commencing to use higher-cost western Canadian coal to reduce its dependence on United States coal. The price of exported energy will increase to the extent that western Canadian coal is charged to the transaction, and this may have a dampening effect on demand. U.S. utilities' expectations of growth, like Ontario Hydro's, have declined, and this tends to reduce sales opportunities. Conversely, the sheer size of the U.S. market, its heavy reliance on oil-fired generation, and the difficulties U.S. utilities are encountering in commissioning coal-fired and nuclear plants all suggest a continuing buoyant market for Ontario's surpluses. Hydro has indicated that the most promising markets for firm power sales appear to be the Central Area Power Co-ordination Group, the Michigan Electric Power Pool, the American Electric Power Service Corporation, and some members of the New York Power Pool, with a total potential in the 500 MW to 1,500 MW range in the 1980s.[2]

Superficially, there is no good reason why the energy in U.S. coal should continue to flow into Ontario for processing and then return to the U.S. in the form of electricity. One might expect that the U.S. could produce electricity from its own coal more economically at home. Institutional biases encourage such flows across the border, however.

The U.S. electricity utility industry is largely investor-owned, profit-oriented, and subject to taxation on income and to constraints on capital funding. While the industry is much larger than Canada's in aggregate, it is more fragmented. Some 200 investor-owned utilities own about 75 per cent of the generating capacity, five large federal agencies have 12 per cent of it, and the remaining 13 per cent is owned by hundreds of small investor-owned utilities and by state, municipal, and other non-federal agencies.

The Ontario Hydro system is larger and more diversified than any of the U.S. utilities with whom it deals. Its plant is more capital-intensive and has relatively lower incremental production costs. The system comprises mainly hydraulic, nuclear, and large and efficient coal-fired steam turbine generation. Its U.S. neighbours, on the other hand, have a large share of plants with high fuel costs, such as oil-fired, gas-fired, and less efficient coal-fired plants. So, for economic reasons, there is a tendency for power to flow from north to south. Export opportunities may be expected to remain at a high level, at least until the U.S. utilities substantially increase the mix of their nuclear and coal-fired capacity.

Similar considerations apply all along the Canada-U.S. border, and over the last few years a number of provinces have stepped up their power exports to the United States. British Columbia, Saskatchewan, Manitoba, Quebec, and New Brunswick now have substantial interchange capability with contiguous American utilities. There is an understandable preference to market southwards into the higher-priced U.S. market, particularly since the requisite interconnections are shorter and less costly than those between provinces.

The era of long-term fixed-price imports of firm hydroelectric power from neighbouring provinces appears to have ended, at least for a few years. The last such contract with Quebec terminated in 1977. Ontario's only remaining major firm-power contract provides for the purchase of about 200 MW from Manitoba Hydro each year up to and including 1981. Ontario Hydro now plans well ahead, to ensure that it will have adequate generating capacity for its needs. Indeed, with the prospect of a substantial surplus for most of the coming decade, Ontario is unlikely to buy anything but secondary hydroelectric energy from Manitoba and Quebec during that period.

On the face of it, it appears desirable for Ontario Hydro to resume the purchase of firm hydroelectric power from its neighbouring provinces on a medium-term basis, as soon as it is in a position to do so. Substantial hydroelectric resources remain to be developed in Quebec, Labrador, and Manitoba; it appears desirable, especially in the interests of conserving non-renewable resources, for them to accelerate the development of these resources and use the resulting capacity to supply other markets, including Ontario, until this capacity is required for their own purposes.

However, hydroelectric projects in the remote regions of Canada tend to be highly capital-intensive, which may present problems in financing them. Also, the unit capital cost of an additional station may be less than the average unit capital cost of the whole project. In these circumstances, it is difficult to price medium-term sales of firm power on a mutually acceptable basis. Furthermore, Manitoba and Quebec may prefer to sell to U.S. utilities rather than to Ontario Hydro, if they can obtain a better price from them. This preference will be reinforced, if, as is generally the case, the interprovincial interconnections are more costly than the international ones. However, the total economic benefit to Canada may be increased, and broader regional or national goals may be better served, if the interprovincial

transaction proceeds. Just as with other major transportation and communication links, there is an element of nation-building in the establishment of interprovincial interconnections.

Another uncertain factor that will affect future interconnection transactions is the availability of power transfer capability. Ontario Hydro plans to add a 345 kV interconnection at Niagara in 1983. Hydro estimates that this will increase its total transfer capability to the United States to about 3,000 MW.[3] At the Commission's hearings on bulk power facilities for southwestern Ontario, it noted that the transfer capability will decline after 1983 unless new bulk power transmission facilities are installed in southwestern Ontario. The existing main transmission lines westward into London that supply loads in the London-Windsor-Sarnia area also transmit some of the power to be exported to Michigan. To avoid overloading these circuits, the export capability drops as the domestic loads increase.

In similar vein, at the Commission's hearings on bulk power facilities in eastern Ontario, Ontario Hydro showed that the growing load in the Ottawa area will restrict the amount of power that can be transferred to the New York Power Pool at Cornwall, starting about 1988.[4]

In order to reinforce the transfer capability into the United States, it appears that it may be necessary to strengthen Ontario Hydro's main transmission into southwestern Ontario or into eastern Ontario, or both. Other possibilities may include a submarine cable under Lake Erie from the Nanticoke Generating Station, an interconnection via the Great Lakes Power Company at Sault Ste. Marie, or a further strengthening of the Niagara Falls crossing. Any such step would, of course, depend upon system arrangements on both sides of the border.

The Beauharnois tie from Quebec can still perform a valuable role in the transport of any available power from Quebec. However, it is of limited utility for transferring power from Ontario, since its use for that purpose would jeopardize security of supply to Ottawa.

Because the Ontario-Quebec ties are, for all practical purposes, only a one-way interconnection (Quebec to Ontario), Ontario Hydro considers that valuable opportunities for economic interchange and mutual support between the two systems are not being exploited fully. There has been considerable discussion between Ontario Hydro and Hydro-Québec concerning the construction of a high-voltage, direct-current link between the two systems, but, before such an interconnection could materialize, considerable strengthening of the Ontario Hydro system in eastern Ontario would be required. Hydro-Québec may prefer to establish such a link with the Power Authority of the State of New York instead of with Ontario Hydro, and it is even conceivable that some type of tripartite configuration might be devised.

Transactions with Manitoba are necessarily on a relatively small scale that can be accommodated by Ontario Hydro's West System; Hydro's internal ties are too weak to permit the participation of its much larger East System. A strong transmission link will be required between the West System and the East System to permit the generating capacity in these two systems to be more fully co-ordinated, and to permit increased transfers with the western provinces.

The Role of the National Energy Board (NEB)

The export of electricity from Canada requires a licence from the National Energy Board. At one time, Canada was reluctant to authorize exports, and they were subject to duty from 1925 until 1963. Since 1963, Canada has viewed electricity exports more favourably, and the government is prepared, upon recommendation by the NEB, to authorize exports when a neighbouring utility needs emergency assistance or when there is an opportunity to sell surplus power profitably. An applicant for an export licence must demonstrate to the NEB that the proposed electricity sales are surplus to foreseeable Canadian requirements that could reasonably be supplied by the applicant and that the price to be charged is just and reasonable in relation to the Canadian public interest. The applicant must also provide NEB with details of any environmental impact that may result from the generation of the power for export.

In the last few years, there has been increased participation in NEB hearings concerning international power lines and electricity exports. Neighbouring provinces and utilities, property owners, environmentalists, and ratepayer groups have intervened, some in support of and some in opposition to the applicants. Neighbouring provinces have not opposed export applications, but on occasion have sought to secure the right of recapture for their own use in certain eventualities. Licences issued by the NEB generally stipulate that the export of interruptible energy be stopped or curtailed whenever and to whatever extent such energy is required to supply any firm load in Canada, or if any Canadian electricity utility is willing to buy part or all of the energy at the same price as that of the export,

adjusted for possible differences in the cost of delivery. However, the NEB has expressed concern that it may be placed in an invidious position in adjudicating between two provincial utilities, on the question of Canadian interest, if and when one utility becomes deficient in generation through lack of adequate planning and through no fault of the other.

"Electricity Exchanges" – A Canada-United States Study

In 1979, the governments of Canada and the United States jointly issued "Electricity Exchanges", a report on a study that examines the potential for increasing electricity exchanges between the two countries.[5]

The participants in the study were regional representatives of the electricity utilities along the United States-Canada border, federal officials of both countries, and representatives of the Canadian provincial governments except for Quebec, which declined an invitation to participate. Observers from the Quebec government and Hydro-Québec participated in organizational meetings.

Representatives of the Ontario Ministry of Energy and Ontario Hydro participated in the study group for the Ontario-New York-ECAR region. ECAR is the East Central Area Reliability Co-ordination Agreement, one of the regional reliability councils that make up the U.S. National Electric Reliability Council. It includes utilities in eight states, including Michigan, Ohio, and Pennsylvania.

For the Ontario-New York-ECAR region, the report on the study notes that the expected transfer capability in 1980 is as shown in Table 5.2. But the report also states that these transfer capabilities will decline unless the Niagara interconnections are strengthened and the internal transmission capacity constraints within the Ontario-to-Michigan interface are overcome. The report concludes that if these transmission limitations are resolved, there is considerable potential for increased operational co-ordination to stimulate economic exchange – for example, the use of excess coal-fired generation in Ontario to reduce oil consumption in New York and Michigan and in utilities farther south. In addition, there may be significant possibilities for seasonal diversity exchanges between Ontario and utilities to the south of New York and Michigan.

Table 5.2 Expected Power Transfer Capability between Ontario and the U.S. in 1980

Transfers	Summer transfers to U.S. (MW)	Winter transfers to Ontario (MW)
Ontario and Michigan (zero to New York)	1,200–2,000	600–1,100
Ontario and New York (zero to Michigan)	1,500–2,200	1,300–2,000
Ontario, Michigan and New York (simultaneous)	2,000–2,700	1,700–2,400

Note: Transfer capabilities shown are based on a range of 0–400 MW circulating current around Lake Erie in a counter-clockwise direction.
Source: "Canada/United States: Electricity Exchanges", U.S. Department of Energy and Energy, Mines and Resources Canada, May 1976.

In order to realize fully the benefits of interconnections, "Electricity Exchanges" suggests, utilities near the U.S.-Canada border should maximize co-ordination of system planning and operation, expand the sharing of technical information, ensure that applications for electricity exports are filed in a timely manner, and develop mutually agreeable interchange rates and wheeling rates in the U.S. to encourage participation by utilities not directly adjacent to the border in international electricity trades. The report also recommends that the federal, state, or provincial governments and regulatory agencies should clarify government policies relating to firm exports and exports in general, effect increased communications among regulatory agencies and electricity utilities to expedite regulatory approval, develop public information programmes, and ensure that pricing policies are consistent with a fair sharing of interconnection benefits.

Interprovincial Interconnections

The Provincial Utility Systems

Because of the provisions of the British North America Act, which gives each province jurisdiction over the natural resources within its boundaries, the production and distribution of electricity is subject mainly to the provincial jurisdictions. Each province has developed a province-wide transmission system that interconnects most of its generation and load centres. These province-wide systems permit generation to be planned, constructed, and operated in a co-ordinated manner, so as to meet provincial requirements for electricity as economically as possible.

Canada's immense distances and thinly distributed population make the forging of interprovincial links a costly undertaking. However, numerous important links have already been put into place, and a number of additional major links are receiving active consideration through bilateral discussions between the utilities directly concerned.

The Federal Government

The federal government has a large and growing presence in electricity matters. It regulates electricity exports through the NEB. Through the Northern Canada Power Commission, it produces and markets electricity in the Yukon and Northwest Territories; and through Atomic Energy of Canada Ltd. it owns several nuclear power plants and has a financial interest in others. It has granted funds towards the construction of some provincial generation and transmission facilities and has invested funds in some others. Federal statutes and policies influence provincial electricity utility affairs in numerous other ways. For example, the federal government is responsible for international boundary waters and navigable waters and for the regulation and control of some aspects of fossil and nuclear fuel production, transportation, and utilization.

The federal government probably has the constitutional authority to regulate interprovincial electricity trade if it chooses to do so. There appears to be little likelihood, however, that it would take any unilateral action in this respect. It has preferred to foster strengthened interprovincial interconnections in close co-operation with the provinces concerned.

Federal-Provincial Studies

From time to time, the provincial and federal governments have given preliminary consideration to the establishment of high-capacity interprovincial interconnections that would result in a Canada-wide power network.

A federal-provincial working committee on long-distance transmission made studies during the period 1962-7. While these studies suggested that the interconnection and co-ordinated development of the power systems of all the provinces would be economically beneficial, it was concluded that such benefits were marginal. Further action was deferred.

The energy crisis of 1973 renewed interest in the idea of a Canada-wide power grid. While priority consideration has necessarily been given to oil, the federal and provincial energy ministries have seen strengthened electricity interconnections as a potential part of a balanced policy for promoting the conservation and prudent utilization of all forms of energy. The federal government recognized the importance of strengthening interprovincial interconnections in a 1976 report – "An Energy Strategy for Canada: Policies for Self Reliance" – and advocated the acceleration of such developments and closer co-ordination in the joint planning and development of power projects by the provincial utilities.[6] The report also noted:

> In January of 1974, the Minister of Energy, Mines and Resources announced that the Government of Canada would pay 50 per cent of the cost of approved studies relating to interprovincial or interregional electrical interconnections and finance up to 50 per cent of the capital cost of approved projects.

Thus, it is reasonable to assume that any initiative by the provinces to strengthen interprovincial interconnections is likely to enjoy the support of the federal government.

Interprovincial Advisory Council on Energy (IPACE)

During 1978, the Interprovincial Advisory Council on Energy, which brings the provincial deputy ministers of energy together in conference, sponsored a preliminary study comparing the benefits to be gained from continued normal inter-utility development with those that could be gained through the pooled expansion of combined power systems. The results of the study were released in October 1978 in a report entitled "An Evaluation of Strengthened Interprovincial Interconnections of Electric Power Systems".[7] In general, the report concluded that:

> The putting in place of high-capacity electric transmission interconnections between the provinces at the earliest feasible date would create the infrastructure required for electric energy to contribute fully to the objectives of a national energy strategy.

And that:

> Within the scope of the examination made in this study, the prospective advantages of a strengthened interprovincial network merit further consideration.

And that:

> Satisfactory arrangements for the establishment of a network of strengthened interprovincial interconnections can be made provided that all parties have a desire to find a mutually satisfactory solution and are willing to extend their cooperation to that end.

The conceptual plan analysed by the IPACE study group calls for a total interprovincial transfer capability of 13,650 MW by 2000. The existing capability is 1,330 MW and the additions under consideration by the utilities would bring this to 6,130 MW by 2000. Thus the IPACE conceptual plan contemplates an additional capability of 7,520 MW. The corresponding data for interconnections with Ontario are given in Table 5.3. The foregoing figures exclude the transmission capability dedicated to bringing power from Churchill Falls in Labrador to load centres in Quebec and the transfer capability that can be achieved by isolating certain generating stations (see Appendix C).

Table 5.3 Interconnections between Ontario and Its Neighbouring Provinces

	Ontario-Quebec[a]	Ontario-Manitoba
Existing (MW)	0	260
Under consideration by utilities (MW)	2,000 HVDC	260
IPACE plan (MW)	2,000 HVDC	2,000 HVDC
Total (MW)	4,000	3,520

Note a) Does not include the ability to isolate up to 1,300 MW of certain Quebec generation for the Ontario system.
Source: IPACE Study, vol. 1, pp. 13-14.

An economic analysis of the conceptual plan indicates a modest net economic advantage, particularly if fuel prices continue to escalate relative to other costs. The economic benefit is realized by the reduction in expenditures on generating capacity due to load diversity and the sharing of generation reserves, and by fuel cost savings through co-ordinated operation resulting in better utilization of hydraulic and nuclear resources. The report also noted:

> Other benefits provided by the plan but to which no dollars were attached include opportunities to develop power projects on a regional basis, increased security of electricity supply, enhanced flexibility to adapt to changing fuel supplies and electricity demands, and flexibility of response to changing energy policies.

The IPACE study proposes the formation of an interprovincial power co-ordinating council (IPCC) to promote co-ordinated operation and planning of the provincial utility systems over strengthened interconnections. IPCC would make the basic arrangements for financing, constructing, and operating the systems, for ratification by the provinces prior to implementation. To avoid all uncertainty as to constitutional jurisdiction, IPCC should operate with authority delegated from the federal government as well as from the provinces.

IPCC could operate the entire system as an interprovincial power pool in which the utilities would participate in accordance with the provisions of an interprovincial power pool agreement. The interprovincial power pool would function in a manner similar to other power pools, in the United States and overseas, and would offer flexibility of options to the participants. Operation of the installed generating capacity on the provincial utility systems would be co-ordinated so as to minimize the total cost of electricity production consistent with safe, reliable operation and with environmental and other constraints. Mechanisms would be provided for co-ordinated planning of provincial generation programmes in a manner that would ensure that the basic responsibility for these development programmes would remain with the individual provinces. Each province would continue to plan and execute its own generation development programmes. The IPCC would review these plans periodically to identify opportunities for provinces to realize economies through the development of joint projects and, with the concurrence of the provincial utilities, to make arrangements that define the extent and duration of the participation by each party. The pool agreement would also specify the amounts of reserve generating capacity to be carried by the provincial utilities and the ways in which it would be shared in emergencies.

In order to establish major interprovincial interconnections, it will be necessary to resolve a number of financial matters that are of critical importance to the success of the undertaking. In particular, it will be necessary to determine an appropriate allocation of costs and benefits among the participating governments and utilities, including the interrelated matters of the financing of the requisite capital works and the pricing of interprovincial transfers of electricity. A number of considerations suggest

that it may be appropriate that governments assist in supplying the funds in excess of those required for independent utility developments. The future stream of benefits over the life of the strengthened interprovincial interconnections is uncertain, and some major benefits, such as improved reliability, cannot be estimated in financial terms. There may be no direct relationship between the locations of the electric power facilities and the regions where benefits are realized. A utility should not be expected to provide funding except for use in its own province and to the extent that benefits are assured to it. It appears appropriate that the balance of the funding should be provided by governments, for these reasons and in order to expedite the installation of strengthened interconnections anticipating the realization of broader provincial and national benefits.

The IPACE study is already more than a year old. The data and load forecasts for the conceptual plan were provided by the provincial utilities and were based on expectations in late 1977. The load forecasts and planned expansion programmes have subsequently been reduced, at least in Ontario. This will have some impact on the estimates of the conceptual plan. However, the purpose of the conceptual plan was simply to raise possibilities and suggest preliminary conclusions. It has served that purpose well. The implications for Ontario of the IPACE conceptual plan deserve further consideration.

Interconnections within Ontario

Ontario Hydro is the predominant producer of electric power in Ontario, but it is not the only one. Statistics for 1976 indicate that 95 per cent of the generation is owned by Ontario Hydro or under its direct operational control. Other utilities own 351 MW or 1.6 per cent. Most of this is owned by the Great Lakes Power Corporation (202 MW), the Canadian Niagara Power Company (95 MW), and the Gananoque Light and Water Company (11 MW). About a dozen municipal electricity utilities, mostly members of the Ontario Hydro family, own 43 MW. Industries own 820 MW or 3.6 per cent of the provincial total. This includes about 10 with 300 MW of hydraulic generation and about 20 with 520 MW of fossil-fuelled generation, used mainly for the joint production of electricity and steam. A few of these industries operate small distributing utilities.

Most of the small Ontario producers augment their supplies with power purchased from Ontario Hydro under the standard municipal electric or direct industrial tariffs. They may also purchase stand-by service from Ontario Hydro to safeguard against the unavailability of their own generation. Indeed, Ontario Hydro's posted prices provide the criterion against which prospective producers determine whether it is economical to install and operate their own production plants. This creates an institutional bias that may discourage small producers, if the posted prices are lower than their marginal internal costs.

Ontario Hydro purchases electricity from some small producers, such as the Mattawa Electric Light and Power Company and the Great Lakes Power Corporation. In 1977, these purchases from Ontario suppliers amounted to 464 GW·h, or 0.45 per cent, of Ontario Hydro's total resources.[8]

On occasion, Ontario Hydro wheels power for the small producers, for example, from the Canadian Niagara Power Company to the St. Lawrence Power Company, both of which are subsidiaries of the Niagara Mohawk Power Corporation of New York State. In a recent move, Ontario Hydro has undertaken to wheel power for Dow Chemical of Canada Limited from Sarnia to the international border, for forwarding by the Michigan utilities to Dow Chemical in Michigan.

In the United States, the role of the small municipal electricity producers has been something of a *cause célèbre.* Large investor-owned utilities have been loath to interconnect and co-ordinate with small public municipal utilities and rural co-operatives. The benefits often appear substantial to the smaller party but trivial to the larger one. Furthermore, the larger tax-paying utility may be reluctant to share its economies of scale with the smaller tax-free or even tax-supported utility. When such matters are referred to it, the Federal Energy Regulatory Commission (FERC) has generally ruled that the small utility is entitled to share the benefits of co-ordination, and the U.S. Supreme Court has upheld the FERC on appeal.

Further examination of the role of the small power producer in Ontario would be desirable. An Ontario power pool could be formed, to provide positive encouragement for small power producers to contribute to the total provincial stock of generating capacity.

Conclusions

Ontario Hydro must continue to supply most of Ontario's requirements for electricity from generating stations situated within Ontario, and strategically located with respect to Ontario load centres. Technical, economic, social, and political factors all support Hydro's role as Ontario's chief producer of electricity, mainly for use in Ontario.

Ontario Hydro has conducted a substantial electricity trade with neighbouring provinces and states. A number of considerations suggest the desirability of increasing this trade, not only in absolute terms, but also in terms of its share of the total provincial demand. Escalating fuel and capacity costs have materially increased the value of intersystem transfers. Such transfers can promote the fuller utilization of renewable hydroelectric resources and the conservation of dwindling fossil fuels. Strong interconnections facilitate a flexible response to an uncertain energy future.

Both international electricity trade with the United States and interprovincial trade with other provinces have been beneficial in the past and are expected to be beneficial in the future. The one should not be pursued to the exclusion of the other, nor should the one be delayed on account of the other. Reasonable goals for implementation in the 1990s might be the provision and utilization of transfer capabilities of some 2,000 to 4,000 MW between Ontario Hydro's East System and each of the following: Quebec; the West System and Manitoba; and New York, Michigan, and Ohio.

Power transfer capability with the United States is projected to decline sharply as internal transmission in southern Ontario becomes fully dedicated to provincial loads. To maintain and increase international electricity trade will require the construction of major new transmission facilities. The planning of these facilities will be a complex task – one that must take cognizance of existing and projected power system configurations in Ontario, the border states, and beyond, as well as of alternative land uses and socio-environmental impacts.

While existing interconnection agreements with U.S. utilities apparently serve Ontario's interests well, it will be necessary to review them critically during the planning of this new transmission.

In many respects the strengthening of interprovincial interconnections is more challenging than the strengthening of international interconnections. Strong interconnections with Quebec and Manitoba and their possible extension farther east and west would probably require comprehensive agreements, between the provincial and federal governments as well as between the electricity utilities. The era of firm interprovincial power transfers has ended and must be supplanted by new understandings, possibly incorporating pooling or co-ordination concepts. Reasonable compromises must be sought to accommodate both north-south and east-west transactions.

Ontario Hydro has negotiated mutually beneficial interconnection agreements with utilities in neighbouring states and provinces in the past and is expected to continue to do so in the future, within the framework of jurisdictional constraints. It is desirable to study the implications of Hydro's applying similar methods in its dealings over interconnections with small utilities and industrial producers of electricity within Ontario.

CHAPTER SIX

Operation and Control of the System

The operation of a large power system on a minute-by-minute, day-by-day basis is predicated on matching the generation to the load by making the best use of the available power resources (including assistance over the interconnections), while ensuring an adequate level of reliability and security of the system. The amount of generation that is fed into the system at any instant is exactly equal to the load that is being supplied. This load includes the transmission losses that are associated with the use of the electrical equipment on the system at the time. Generating capacity is added to or taken off the line according to the hourly customer load and scheduled outages or deratings of generating units. Allowance is also made for unscheduled shut-downs of generating units through the so-called "spinning reserve" (generating capacity that is operating, but not loaded to its maximum output).

In matching the generation to the load, a number of alternatives are usually available, in the numbers and types of generating units that can be operated at any given time. The choice is governed by the criteria of maintaining a specified level of system reliability and security (that is, minimizing both the likelihood of a breakdown of supply and the severity of any interruption that does occur) and minimizing the cost of generation. While the possibility of an interruption of supply can never be entirely eliminated, proper system operation procedures can reduce the chance to a minimum.

The Operating Control of a Power System

The operation of a large power system such as Ontario Hydro's is performed by a three-tiered structure of operators (Figure 6.1).

Fig. 6.1: p. 76

At the lowest level are the station operators, their assistants, and their agents, who control the distribution system feeding power from the subtransmission system to the large direct customers, and to the retail distribution systems; and operate, under direction, generating stations and portions of the subtransmission system.

The middle tier of operators are the regional operators and their assistants, who control the subtransmission system within a region of the system; and operate, under direction, portions of the main transmission system.

The highest of the three tiers of operators are the operators and schedulers who man the system's main control centre, for example Ontario Hydro's Richview Control Centre, where they direct the operation of the generating stations, the interconnections with other systems, and the main transmission system, which are collectively called the "bulk power system".

The limits of responsibility for each tier of operators are determined mainly by the operational significance of the various elements of the system rather than by generator capacities, transmission line voltages, or power flows. All generating and transmission equipment that can have a significant effect on the security or economy of the system as a whole is considered to be within the bulk power system's boundaries.

Control of the operation of the bulk power system involves the authorization of the switching of transmission lines and other high-voltage apparatus within the system, the control of voltage levels, the monitoring of power flows and equipment status, the avoidance of security limits, the authorization of any work on or adjacent to the system's high-voltage apparatus and its associated protection and control apparatus, the authorization of all generation and transmission outages, and the scheduling (and subsequent loading) of all generation on the system and of interconnections with neighbouring systems.

The system control centre's operators and schedulers make their normal day-by-day and minute-by-minute decisions according to policies, plans, and directives developed by groups in the power system organization that plan the operation of the system. Policies, plans, and directives governing the two lower tiers of operations are developed by the head office, and by regional and local operations groups. It is the quality of these policies, plans, and directives (and their faithful execution), together with the effectiveness of the responses by all levels of operators to unplanned events, that largely determine the economy, security, and reliability with which the system operates.

The foregoing assumes that adequate protection, indication, control, and communication devices are

provided at all levels of the system. The correct functioning of the automatic protection and control equipment largely determines the system's appropriate response to routine changes, unexpected malfunction and failure of equipment, and actions of the environment.

Protection, Indication, Control, and Communications

Protection

Each item of high-voltage equipment is subject to failure. A failure may be the result of a "fault", that is, an uncontrolled discharge of power between high-voltage conductors and/or between high-voltage conductors and ground. The magnitude of the electric current that is involved in a system fault is such that the system's equipment and public property may be severely damaged and human lives endangered if the fault is prolonged. In addition, system faults can cause instability in the bulk power system. Some examples of failures involving system faults are:

- tree limbs blown against transmission-line conductors
- insulator "flashover" resulting from a lightning stroke
- failure of the insulation in a generator cable, transformer, or circuit-breaker

High-voltage equipment can also suffer failures that do not (at least initially) result in system faults. These failures, however, can result in severe damage to equipment and danger to employees and the public, and can ultimately result in system faults. Examples of such failures are:

- overheating of transformer windings
- excessive vibration in turbine-generator sets
- failure of boiler or turbine auxiliary equipment

In order to prevent damage to equipment and danger to the employees and public, each piece of high-voltage equipment in the system is provided with low-voltage apparatus to detect failures and faults and initiate the disconnecting of the equipment from the system through the opening of circuit-breakers. The functioning of this automatic protection apparatus is designed to remove the faulty equipment as quickly as possible, while avoiding unnecessary removal of the system's other high-voltage equipment.

Because of the complex nature of the system's power flows, of the protection equipment, and of the switchgear, it is not possible to guarantee that faults and failures will be correctly detected and acted upon. Also, there is always the possibility that protection equipment and switchgear will malfunction, resulting either in a failure to disconnect the faulted equipment from the system or in the removal of too much equipment. To guard against the the failure to remove a fault, protection schemes are duplicated and back-up schemes are provided. From a system point of view, the most severe fault conditions occur at higher system voltages and close to sources of generation. Therefore, it is usual to find the more elaborate and speedier protection schemes in such locations.

The portions of the system that are the easiest to protect are those whose function is simply to feed power to load areas, and where, consequently, it is relatively easy to discriminate between load currents and fault currents. However, protection for these portions of the system can be greatly complicated if a number of small generating units are added near the load centres. These units, when mingled with the load, can reverse or alter the direction and magnitude of power flows, which makes it difficult to distinguish between load currents and fault currents.

Indication

At all levels, the system's operators are provided with a variety of indications of the condition of the portion of the system for which they are responsible. Indications include:

- circuit-breaker and switch positions (open or closed)
- voltage measurements
- real and reactive power flows
- generating unit outputs
- transformer tap changer positions

In addition to this type of continuous indication, alarms are provided to alert the operators to such events as:

- the opening of a circuit-breaker by automatic protection apparatus
- a high- or low-voltage condition

- the failure of auxiliary apparatus
- abnormal conditions within high-voltage apparatus (e.g., high temperatures in transformer winding)
- the existence of an undefined abnormal condition at a minor location

All of these indications are necessary, so that the operators are continuously aware of the state of the system and particularly of the portion over which they are exercising control. The operators require this knowledge of the state of the system, so that they can:

- make the alterations that are necessary from time to time to maintain the system's voltage and power-flow conditions within acceptable security limits
- arrange the pattern of generation and interchange in the most economic fashion
- take appropriate action to safeguard the system, and prevent damage to equipment or danger to people
- restore the system to a normal, secure operating state following a disturbance of the sort that could be produced by a fault

At some locations in the system, where there is too much information for a single human mind to assimilate, computers are used to process the information and give the operators a concise picture of the state of the system.

Control

The power system and its operators are provided with a considerable amount of control equipment for use in operating the system. Controls may be automatic or manual, or both. However, all automatic controls are capable of being overridden at the discretion of the operators.

Suitable controls are provided for all items of equipment that are important to the functioning of the system. The controls are too numerous to list in full, but some examples are given below.

- Generators are provided with automatic excitation control so that a desired level of output voltage can be maintained under varying output conditions.
- Many transformers are provided with automatically controlled tap changers so that a constant secondary voltage can be maintained under the changing levels of load being supplied through the transformers.
- Many transmission line circuit-breakers have "auto-reclosing" controls that permit the circuit-breakers to be automatically reclosed after a protection operation has been carried out to clear a fault.
- Many circuit-breakers have remote controls that allow them to be operated from central control locations. Most important among such circuit-breakers are those that are used in conjunction with transmission lines, transformers, customer feeders, and static capacitor banks. The circuit-breaker is the most-used type of control in the system.
- Load, frequency, and tie-line controls are provided at the overall system level to automatically and continuously adjust the output of selected generation units or stations in the most economic fashion to maintain pre-set system export or import, while at the same time responding to frequency variations in the system.
- Generating unit remote controls are used for many remote hydraulic generating stations, to permit operators at central locations to start up, shut down, and control the output of the generators.
- Special system controls are sometimes provided to take care of difficult system situations, in which security limits are being violated and unusual corrective action must be taken so rapidly that there is not time for human response. Ontario's power system has situations such as this in the transport of power out of the Bruce nuclear complex and in the maintaining of adequate voltage in the Ottawa area.
- Load management controls are installed in many systems to permit operators at central locations to switch various end-use devices such as electric hot-water heaters on and off in consumers' premises.

All system elements capable of being operated are, of course, provided with local controls to permit operation.

Communications

The operation and control of a large power system relies heavily on communications. Verbal information and instruction has to be passed between operators at various locations in the system. Information to provide system indications is passed from source to destination over great distances. Control signals are also required, and protection signals and information must often be passed from one end of a transmission line to the other.

All of this communication activity requires a great deal of communication apparatus. Power systems use a variety of media including:

- telephone lines (dedicated or shared)
- private communication cables
- power-line carrier equipment (which uses the transmission lines to carry communication signals)
- point-to-point microwave radio
- mobile microwave radio

In recent years, communications have become so important to the operation of a large power system that it is necessary to provide a system of alarms and indications to exhibit the state of the communications network. Also, for most functions, to safeguard their security it is necessary to provide more than one communications path. The communications network for a large power system can become a system in itself, requiring monitoring and control. Ontario Hydro has a central microwave control room where shift personnel carry on a full-time control function.

The Management of a Bulk Power System

The management of a bulk power system, and its operation, is performed according to criteria that are mainly self-imposed, but derived from industry standards that have developed along with the industry itself. Perhaps the one major exception to this is the area of environmental protection, which is subject to government regulation. Overall, the criteria relate to:

- the need to supply all of the load
- economy
- security
- reliability
- the safety of the public, of utility personnel, and of utility equipment
- the environment

Usually, the power system is managed and operated in such a way as to supply the load with the maximum economy possible without violating standards relating to security, reliability, safety, and the protection of the environment.

The management of a bulk power system is carried out by head office groups that develop policies, plans, and procedures, and analyse all available data to ensure that the system adheres to established design criteria at minimum cost and is able to respond to emergencies, including those in which events cause the design criteria to be exceeded. Specifically, the management of a bulk power system involves:

- developing plans for the utilization of all generating resources and interconnections with other utilities
- developing operating standards and training programmes
- analysing the behaviour of the system on the basis of actual performance, and through transient-analysis and load-flow programmes defining operating limits under various modes of operation
- making recommendations to other work groups concerning the operating acceptability of major alterations or additions to the system
- establishing and monitoring standards for protection, indication, metering, control, and communication apparatus
- analysing the performance of protection equipment and taking the action necessary to correct sub-standard performance
- collecting and analysing relevant statistical data on loads, resources, fuels, stream flows, water levels, and storages

Generally, the management and operation of a bulk power system are divided between electrical operations aspects and economic operations aspects, together with provision for co-ordination at all management and operational levels.

Electrical Operation of the Power System

In simple terms, the management and operation of the electrical aspects of the system are aimed at ensuring as far as possible that the system's loads remain connected and supplied, that the transport capability does not hinder the economic operation of the system, that customer voltages are within correct limits, and that the system does not present a hazard to the public or to the utility's employees. It is also required that equipment be maintained and augmented.

To achieve these aims, the activities of the head office management groups involve:

- developing policies and general instructions for the operators
- establishing limits for the maximum power flows at various points in the system under normal and abnormal conditions in order to prevent equipment overloading and system instability prior to, during, or after faulting or other loss of equipment
- providing correct settings for voltage-regulating equipment
- planning major maintenance and construction outages of transmission equipment
- arranging for special system connections or special operating procedures to cover particular abnormal situations
- analysing the electrical performance of the system

The main computational aids for this work by head office groups are load-flow and transient-stability computer programmes.

The activities of control centre schedulers and other members of the electrical operations staff involve:

- scheduling and co-ordinating the outages of high-voltage equipment and the protection, communication, and control apparatus
- processing information and instructions from the head office groups into a form suitable for the operators
- providing locally developed instructions to the operators
- inputting information and limits into control-centre computer systems
- analysing the results of system operation and passing information to the head office groups

The operators at the various levels of operational control are the people with actual physical control of the system. While the activities of these operators include the continuous carrying out of the instructions and plans provided to them, they also include the continuous monitoring and correction of voltages and power flows. Also, the operators perform the prearranged switching and isolation that is required to render equipment safe to work on. One of the most critical activities of the operators is to respond to sudden abnormal conditions brought about by faults and other malfunctions. The response may require the simple reclosing of circuit-breakers after a temporary fault, the isolation of certain items of equipment and the arranging of their emergency repairs, or the re-connecting of a major portion of the system after a serious disturbance. At high levels of operational control, the operators may be assisted by computer systems that digest system-state information, monitor limits, analyse possible contingencies, and perhaps even suggest corrective strategies.

The greater the number of restrictive system limits (usually brought about by outages or inadequate transmission equipment), the more difficult it is for operators to maintain the system in a secure state with sufficient scope for economic operation, and the more frequent are the occurrences of operator errors.

The Economic Operation of the System

The economic management and operation of the system does not involve as many people as does its electrical operation. Those involved are, primarily, the head office groups that plan system production, the production schedulers and shift operators at the main control centre, and the station operators who control the generating units.

In discussing the function of the head office groups, it is useful to consider the variables that can affect the economic and reliable operation of a generating system.

There are a number of independent or uncontrolled variables:

- system demands
- forced generator outages
- hydraulic inflows
- environmental conditions

- conditions on neighbouring systems
- interruptions to fuel supplies

In coping with the uncertainties that are implied by these uncontrolled variables, the production planners can control a number of other variables:

- generator maintenance schedules
- hydraulic storage discharge strategies
- interchange agreements and contracts with neighbouring systems
- fuel-supply contracts and fuel stockpiles

It is the function of the production planners to produce a co-ordinated set of maintenance schedules, hydraulic resource release plans, interchange contracts, and fuel-supply and fuel-use strategies that can be used to minimize overall production costs while respecting planning criteria for generation and fuel-supply reliability as well as environmental and system security constraints. To produce such a set of plans, the planners make use of sophisticated, computerized mathematical models, as well as of their own judgement based on experience.

The nature of the mathematical techniques that can be applied to these problems is such that the difficulty of arriving at the most economical set of plans increases with any increase in:

- the number of generating units
- the number of types of fuel used in the system
- fuel constraints
- dual-purpose applications (for example, steam and electricity)
- environmental constraints
- transmission limitations

The mathematical models must take adequate account of the physical characteristics of the generating units (the time taken to start them up and shut them down, their ability to change output levels, the change in production cost or water use associated with a change in output level, etc.).

All production plans do of course, exhibit certain predictable characteristics, for example:

- the increase of planned maintenance during low-load months of the year
- the higher expected use of thermal generating units with lower incremental production costs, compared with units with higher incremental costs
- the use of hydraulic generation with good storage to displace the highest-cost thermal generation

The production plans must also take account of the availability of interruptible and managed loads and attempt to optimize their use. Production plans are subject to continual change as new information concerning the uncontrolled variables becomes available.

The production schedulers at the main control centre receive these plans and use them to provide instructions to the operators for the hour-by-hour operation of the generating system. The main instructions to the operators are contained in daily and weekly production schedules. The weekly schedule is revised as often as necessary for the next seven-day period. The production schedule is a set of hourly output levels for each generating unit or station on the system, together with hourly values of power transfer with neighbouring systems at each interchange point. The production schedule is based on up-to-date forecasts of hourly loads, generator availability, environmental conditions, and hydraulic levels and inflows, and it attempts to optimize the use of all available resources including pumped storage, managed loads, interruptible loads, and interchange possibilities, while respecting equipment, fuel, and hydraulic system security and environmental constraints.

Generally, the production schedule is prepared with the aid of a sophisticated computer programme that contains a very detailed mathematical model of the generating resources of the system and takes account of a number of requirements, such as the amount and distribution of operating reserve (the spare generating capacity that can be loaded quickly in emergencies). Again, the creation of the production schedule is complicated by any increase in the number of generators and constraints.

There is a trend towards the use of computer models to provide inputs to the production scheduling process – such as load forecasts and hydraulic inflow forecasts. There is also a trend towards installation of production scheduling programmes on control-centre computer systems, so that updated schedules can be produced from the latest information gathered by the control computers, at any time the system operators desire.

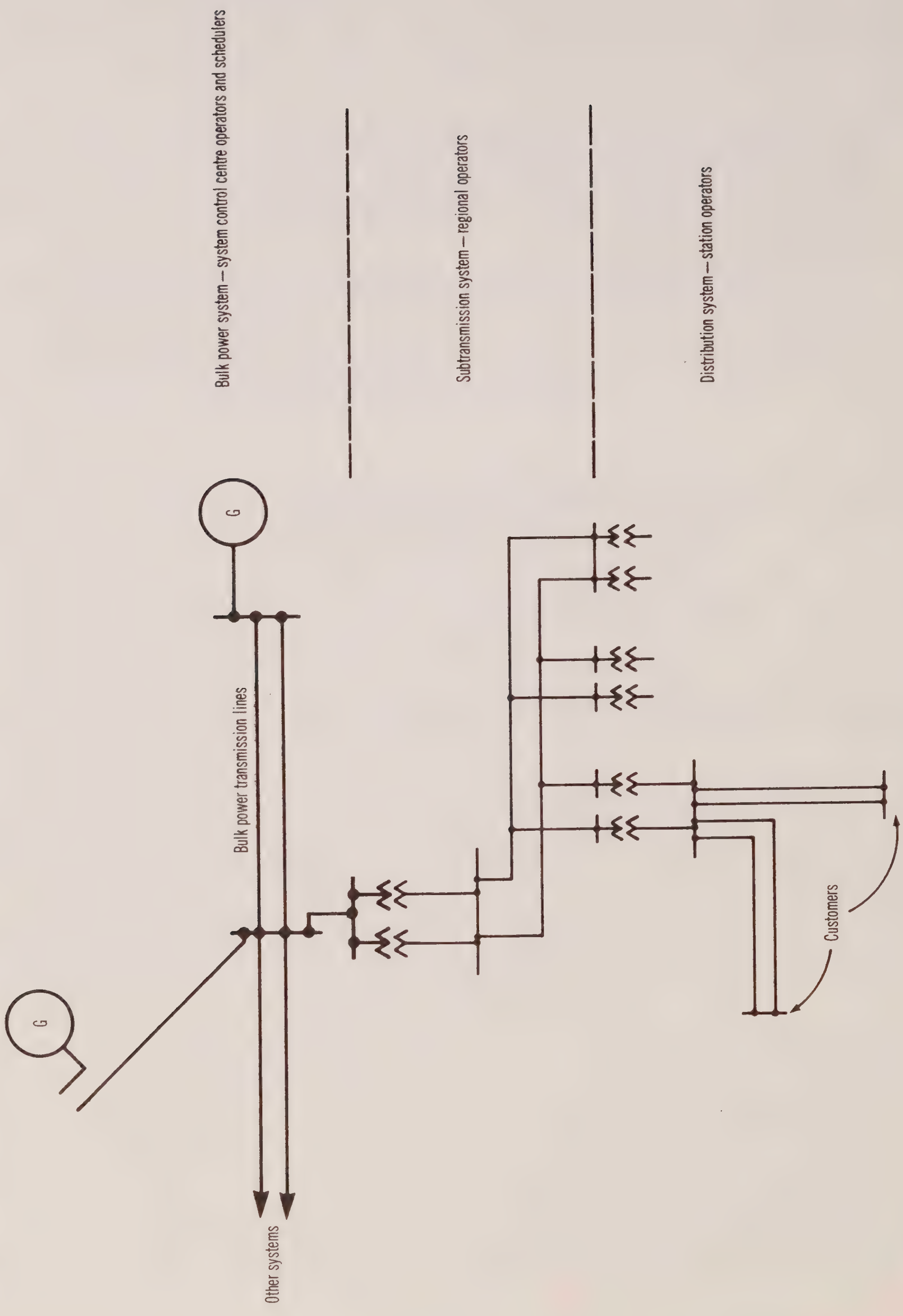
The control-centre operators who are responsible for hour-by-hour system production use the production schedule to arrange the loading of generating units and to arrange economic interchanges of power and energy with neighbouring systems. These operators also place suitable generating units, as defined by the schedule, on automatic load control to respond to minute-to-minute and second-to-second variations in system load. They are also responsible for making emergency changes in unit loadings and interchange flows, to compensate for any loss of system generation equipment or transmission capability on their own or on the neighbouring systems.

The overall results of the system's economic operation exhibit certain predictable characteristics, such as:

- the "stacking", or "merit order loading", of thermal generation, so that the units with the lowest incremental cost are run for the longest periods
- the "shaving" of peak loads by using hydraulic and thermal generating units that have limited energy capability
- generation by pumped storage plants during peak-load hours, and the pumping of water into storage during low-load hours
- the reserve capacity maintained through the units that have rapid response characteristics
- the reduction overnight to minimum load of large thermal units that take a long time to shut down and start up

The actual production on the system is analysed by the schedulers and production planners whose job it is to identify correctable problems, that have prevented the system from achieving its economic optimum.

Figure. 6.1 Levels of Operational Control of a Power System



Source: RCEPP.

CHAPTER SEVEN

The Planning of the Electric Power System in Ontario

The purpose of an electric power system is to supply a geographical region with the electric power and energy needed for its homes, industries, farms, and institutions – reliably and at "reasonable cost". The planner of such a system has the task of defining as explicitly as possible the optimal strategy for its development, so that the costs and the benefits of a service of the desired quality are in balance. The questions the planner must address, and find answers for in the context of the new generation, transmission, and distribution facilities, are: What type? How much? When? and Where?

The Changing Planning Environment

A basic input to the process of planning is the demand for electric power and energy. From 1935 until recently, the demand for electric energy in Ontario grew at a rate of about 7 per cent per year. Both the growth in demand and the retiring of old facilities due to ageing or obsolescence require that new facilities be added to the system. Planning in today's climate for the addition of new facilities is a challenging task because of the long lead time associated with major facilities and the uncertainty concerning the growth in demand over the lead-time period.

The total lead time for a major generating facility is between 10 and 15 years (see Chapter 3), and for a major transmission line it is about eight years. Before the OPEC oil embargo in 1973, the growth in the electricity utility industry in North America was quite regular, and the forecasts over a 10-year period were reasonably accurate. In Ontario Hydro's case, the forecasting errors within a 10-year period were generally less than 10 per cent.[1]

In the days of steady growth in demand and short lead times, the task of system planning was comparatively simple. The inflation rate was low, fuel supply and sound financing were regarded as assured, and cost estimates were assumed by planners to be reliable. The environmental impact of electric power production and supply had not yet become a social issue, and thus the acquisition of land for generating stations and transmission rights of way was not a major problem. The load forecaster gave his projections to the system planner, whose time was spent mainly on immediate capacity additions rather than on system plans for 15 or 20 years ahead.

However, this situation changed dramatically in the 1970s. The forecast made in 1969 for peak demand in Ontario in 1978 was about 30 per cent higher than the demand turned out to be. Ontario Hydro's forecast of the average annual growth rate for demand in the 1980s has dropped steadily from about seven per cent in 1975 to 4.7 per cent in 1979. Some experts believe that even this forecast is too high and predict a 3 per cent annual rate of growth.

Other factors that have altered many of the traditional concepts of system planning are: the impact of alternative technologies, uncertainty concerning fuel and capital availability, and unforeseen plant shut-downs. Alternative technologies – co-generation, heat pumps, solar heating, biomass – will have their influence, but their precise eventual role is difficult to foresee. Most large-scale conventional generating plants cost hundreds of millions of dollars (the estimated cost of Pickering B, coming into service in 1981, is about $2 billion. The size of the investment, combined with the long lead times, makes the financing of such plants a major undertaking. Before a plant is built, the supply of fuel over the plant's service life (normally 30 years) must be reasonably assured. Plants may be shut down for extended periods by regulatory agencies of the government or by the utility itself, for safety or environmental reasons. For example, Ontario Hydro recently announced that it plans to take the four Pickering A units and the first three Bruce A units out of service for one year each starting in 1985, to replace pressure tubes that have stretched more than expected. In March 1979, the U.S. Nuclear Regulatory Commission (NRC) ordered the shutting down of five nuclear power plants in the northeastern U.S. because of doubts about their ability to withstand earthquakes. The NRC ordered the shut-downs after the firm that designed all five plants discovered a mathematical error in the computer programmes that were used to design some of the plants' cooling systems.

These uncertainties may culminate in either an excess or a shortfall in the capacity of the electric power system. In either case, the result will be to increase the cost of power to the customer. The largest single component of the cost of excess capacity is the interest on the capital borrowed to finance the construction of the capacity. Other charges, such as depreciation and operations and maintenance costs, depend

on whether the capacity is in service or "mothballed". It is possible to offset the cost of excess capacity by finding export markets. At present, Ontario Hydro has an excess capacity of about 3,400 MW (that is, 3,400 MW in excess of the 25 per cent generating reserve margin required over the annual firm peak load). On the basis of the capital cost of units 5 to 8 of the Nanticoke Generating Station, the cost of this excess capacity is approximately $100 million a year. Hydro is pursuing the exporting of firm power to U.S. utilities in order to reduce this surplus and has had some success (see the section on the outlook for electricity trade in Chapter 5).

The cost of a shortfall in capacity is the loss sustained by customers due to interruptions of supply. The cost of a shortfall depends on many factors; important among them are the type of customer (industrial, commercial, or residential), the size, frequency, and duration of the interruption, and whether the customer receives sufficient advance notification. Ontario Hydro's estimates of the cost of interruption, based on a survey of large industrial users, range from $0 to $91/kW for a one-hour interruption.[2] A shortfall in system capacity does not always result in an interruption of service. Hydro and many North American utilities are interconnected with their neighbours, and in an emergency a utility may be able to purchase power to minimize interruptions. The price of the purchased power may be quite high, however.

Having discussed the factors crucial to planning in today's environment, we will outline the basic methodology used by the electricity utilities for system planning and then look into Ontario Hydro's practice and policies with respect to planning its electric power system. Since the responsibility for the distribution of electric power in Ontario lies to a large extent with municipal electricity utilities, we will focus our attention on planning for generation and bulk power transmission.

The General Approach to Planning Generation

The first element in the methodology for planning the addition of new generating facilities is a load forecast for 15 to 20 years ahead. This forecast includes not only the peak demand but also the amount of energy that will have to be supplied from year to year and the possible changes in future load characteristics.

In determining the amount of new generating capacity that will be needed, two more factors are significant. In order to meet the peak-load conditions in some future year at a specified level of reliability, a certain amount of reserve capacity is required for protection against forced and scheduled plant shut-downs and deratings (see Chapter 4). While the actual amount of reserve capacity that will be required depends on the configuration of the system, an initial estimate may be made in the form of a percentage based on experience and judgement, e.g., 25 per cent for the Ontario Hydro system. In addition, it will be necessary to replace existing capacity after it has completed its useful life. Thus, the expected growth in load, the associated reserve margin, and an allowance for plant retirement provide the system planner with an estimate of the total amount of new generating capacity that will be required over the planning period.

The next step is to determine which of the alternative forms of generation should be used to meet the new capacity requirement. This involves an economic study of these alternatives to determine their suitability for supplying loads of various durations, taking into account the operating characteristics of the alternatives. With this information, along with the data on generating capacity, existing and under construction, the system planner is able to formulate some broad guidelines for the expansion of the generating system. Starting with these guidelines, the planner develops a number of feasible alternative plans with a view to discovering the "optimum" plan. Considerations that may restrict the number of feasible alternatives are capital, fuel, site and manpower availability, and environmental impact. The process of determining the "optimum" plan is clearly iterative. Each alternative plan is evaluated in conjunction with the load forecast, to obtain estimates of capital requirements, fuel requirements, operating costs, reliability, manpower requirements, etc. The plan with the minimum cost that also satisfies the reliability and other constraints is selected as the basis for system expansion.

Ontario Hydro's Long-Range Generation Forecasts

Ontario Hydro, like many other utilities, plans its future development of generation resources to meet the forecast growth in load at a given level of reliability. These plans are subject to the constraints of capital and fuel availability, environmental impact, and safety. Between 1974 and 1977, Hydro proposed three basic long-range forecasts (LRFs) in the face of changing load forecasts and the constraints on borrowing imposed by the government. These are identified as LRF 41, LRF 43, and LRF 48. In January 1975, Hydro's Board of Directors selected LRF 41A, a variation of plan 41, for use in hearings before the Ontario Energy Board. Soon after that, LRF 43 was developed to conform to the 1975 load forecast.

In July 1975, the Treasurer of Ontario asked Ontario Hydro to reduce its capital expenditures to 1985 by $1 billion. In response to this request, Hydro modified its plans and proposed LRF 43P (Table 7.1). The 1976 load forecast indicated a slight drop in the expected growth in load. Hydro was therefore asked by the Treasurer to limit its capital borrowings in 1976, 1977, and 1978 to $1.5 billion each year. Later in 1976, Hydro modified its 1976 forecast to allow for the likely impact of load-management and conservation programmes. To incorporate these changes, Hydro produced LRF 48 (Table 7.1). However, the load forecasts continued their downward trend, and, consequently, LRF 48 was modified slightly (LRF 48A in Table 7.1) to conform to the 1977 load forecast. The first major departure from the historical exponential load growth at 6.5 to 7 per cent annually was evident in the 1978 load forecast, which projected an annual growth rate of 5.4 per cent over the next two decades. A considerably smaller, yet still large, generation plan called "Program Z" was proposed in response to the 1978 load forecast (Table 7.1). Hydro's 1979 forecast indicated yet another significant drop in load growth (4.5 per cent per annum to 2000). We will discuss Hydro's current generation programme in a later section.

Table 7.1 Ontario Hydro East System – Load and Generation Forecasts (1980-95)

Load forecast	1975	1976	1977	1978
Average annual growth rate (%)	7.05	6.85	6.4	5.4
LRF	43P	48	48A	"Z"
1995 Primary peak (MW)	57,203	52,020	48,492	38,182
1995 Generating mix (MW)				
oil and gas	5,425	5,425	5,425	4,325
(%)	7.6	8.8	9	9.1
coal	22,562	19,562	19,562	14,318
(%)	31.6	31.7	32.3	30.0
nuclear	37,714	30.984	29,856	23,348
(%)	52.8	50.2	49.3	48.9
hydraulic	5,710	5,710	5,710	5,710
(%)	8.0	9.3	9.4	12.0
1995 Total capacity (MW)	71,411	61,671	60,553	47,701
Reserve on primary peak (%)	25	19	25	25

Source: RCEPP.

Most of Ontario Hydro's LRFs cover a period of 20 years. Hydro has stated that, because of the uncertainties about future load and generation requirements, it is not reasonable to expect to be able to devise a single, specific, fixed, year-by-year programme of new facilities for the next 20 years. Each new project is authorized for design and construction only when that is essential. However, the LRFs are necessary to set guidelines for the authorization of new projects and to ensure that each project, once built, will be useful throughout its life. These guidelines relate to the projected nature, timing, and amount of new generation capacity.

As with most utilities, Ontario Hydro's primary basis for the selection of a long-range plan is the minimization of economic costs. However, the nature of these costs has changed. Until recently, they were the long-run costs to Hydro, but now there is more emphasis on the short-run cost of power to the customer, reflecting the effects of raising funds for capital construction. As mentioned earlier, between 1975 and 1977, the generation programmes were also constrained by the provincial borrowing limits.

Although Ontario Hydro planners use sophisticated mathematical models to evaluate reliability and economic costs of generation alternatives, they also use their own judgement in weighing qualitative

factors that are difficult to incorporate into mathematical models. These factors include the socio-environmental constraints and the uncertainty associated with the dominant planning variables – load forecasts, capital availability, lead times, fuel supplies, and the effect of load management and conservation. The nature of Hydro's long-range generation programmes has been described as follows:[3]

> The generation programs that you see are a best-guess forecast by Ontario Hydro or the planners at any given instant as to what we think the most likely generation program will be. It is primarily used as an internal forecasting tool. We are not saying on a given set of rules, such as civil engineering economics, that it is an optimum generation program; really, it is somewhat an optimum generation program which includes all constraints that we can both quantify and study and the ones that we cannot quantify.

Ontario Hydro, in 1976, presented to the Commission its basis for selecting the generation expansion programme LRF 48.[4] Below is a summary of the factors Hydro mentioned. There is no evidence to date to indicate any significant departure from them.

- CANDU nuclear units should be used, as much as possible, for future base-load requirements.
- Future fossil-steam units should be based on coal, and major commitments to oil- or gas-fired units should be avoided. These units, along with further hydraulic and energy-storage schemes, should be used for reserve, peaking, and intermediate-load applications. Coal-fired generation should also be used to supply the part of base load that is not supplied by nuclear or base-load hydraulic units.
- Increased reliance should be put on western Canadian coal, assuming that the cost is reasonable.
- New thermal stations should be large and centrally located near large bodies of water. However, smaller multi-purpose stations, which may become economic, may be located inland.
- New electricity generation technologies – solar, wind, geothermal, fusion, etc. – are not expected to have a major impact until 2000.
- Development of the hydraulic potential of the rivers flowing into James Bay and Hudson Bay is likely to be affected by economic, social, environmental, and political considerations.
- Purchases from neighbouring utilities should be undertaken when economic.

These broad planning concepts are appropriate as they apply to the reliability and operational aspects of system design. However, there are also many economic, environmental, social, and political issues related to these concepts, and they are discussed in other volumes of this Report. As indicated in Chapter 3, the principles of flexibility of the planning process and resilient system design must be associated with these broad concepts.

An understanding of Ontario Hydro's planning objectives with respect to generating mix and reliability may be obtained by comparing Hydro's long-range generation forecasts. Table 7.1 presents the key elements of four long-range forecasts: LRF 43P, LRF 48, LRF 48A, and "Program Z". (Hydro's 1979 generation programme is discussed in a later section.) Between 1975 and 1978, the forecast average annual growth rate for primary peak over the 1980-95 period declined from 7.05 per cent to 5.4 per cent, resulting in a reduction of about 19,000 MW in the predicted primary peak for 1995, from 57,203 MW to 38,182 MW.

Table 7.1 shows that while the total planned capacity drops with the demand, the generating capacity mix does not change by any significant amount. The total hydraulic capacity remains constant at the current level, and, as the forecast load drops, its share in the 1995 system increases from 8 per cent to 12 per cent. This increase in the hydraulic share is offset by a corresponding reduction in the share of nuclear capacity. The shares of coal- and oil- and gas-fired generating capacity do not change greatly. It is reasonable to conclude that, under various LRFs, the planned capacity mix for 1995 is approximately 50 per cent nuclear, 30 per cent coal, 10 per cent hydroelectric, and 10 per cent oil and gas. As will be seen later, this approximate capacity mix also applies to the 1979 generation forecast. It is interesting to note that the 1977 forecast of the primary peak in 1995 is about 3,500 MW lower than the 1976 forecast, but the corresponding capacity reduction is only about 1,000 MW (Table 7.1). The main purpose of this appears to be to restore the reserve margin (which was compromised because of capital constraints) to the "pre-constraint" level.

Figures 7.1 and 7.2 illustrate how measures of generating mix and reliability vary between 1980 and 1995 under the four LRFs. Figure 7.1 shows the planned share of nuclear capacity as a percentage of firm peak demand. A major impact of capital constraints on the generation programme is apparent by comparing LRF 43P and LRF 48. The share of nuclear in LRF 48 is consistently 5 to 8 per cent less than

Fig. 7.1: p

Fig. 7.2: p. 93 in LRF 43P beyond the mid 1980s. This caused a corresponding reduction in the reserve margin over the same period (Figure 7.2).

The severity of the capital constraints imposed on LRF 43P and LRF 48 was reduced considerably when LRF 48A was presented, with a much lower 1977 load forecast. The planned share of nuclear capacity and the reserve margin both rose materially (Figures 7.1 and 7.2). In terms of their size, generation programmes LRF 48 and LRF 48A were not very different (Table 7.1); LRF 48A has 1,000 MW less nuclear capacity than LRF 48. A key factor in the development of LRF 48A was the problem of scheduling generation at sites owned by Ontario Hydro.

With the substantially reduced 1978 load forecast and corresponding "Program Z", the long-term effect of capital constraints disappeared. The nuclear capacity's share of the firm peak load in 1995 is about 65 per cent (Figure 7.1), and this, combined with about 2,800 MW of existing base-load hydroelectric capacity, is close to Ontario Hydro's base-load requirements. The planned reserve levels under "Program Z" are also considerably higher (Figure 7.2). The cause of excessive reserve margins throughout the 1980s is that the committed nuclear programme was not deferred and the only reduction made to the fossil programme over this period was the cancellation of two of the four projected 547 MW oil-fired units at the Wesleyville Generating Station. The reasons given by Hydro for not deferring the committed programme were the cost of electricity to the customers, employment, and the likely impact on the provincial economy of a slow-down.

On the basis of the analysis presented in this section, the following observations may be made:

- Because of their short-to-intermediate-term nature, the capital constraints did not greatly affect Ontario Hydro's long-term generating mix.
- A change in load forecast did not affect Hydro's long-term generating mix.
- There was a significant impact on the planned system reserve margins as a result of capital constraints.
- The generation programmes did not necessarily change as the load forecasts changed, but the projected reliability standards changed.
- Ontario Hydro's planned long-term mix of generating capacity in this century is 50 per cent nuclear, 30 per cent coal, 10 per cent hydroelectric, and 10 per cent oil and gas. (It should be noted that the share of existing and committed hydroelectric and oil- and gas-fired capacity may rise as the load forecast drops. This may cause the share of coal-fired capacity to decrease. For example, the generating capacity mix in 2000 under the 1979 generation plan is 50 per cent nuclear, 26 per cent coal, 15 per cent hydroelectric, and 9 per cent oil and gas.) The planned mix of capacities is not the same as the mix determined purely from the considerations of cost economics, which is about 65 per cent nuclear (see Chapter 3).

System Expansion Program Reassessment (SEPR) Study

In September 1976, the Board of Directors of Ontario Hydro ordered a complete reassessment of the corporation's system expansion programme along with a review of all the factors connected with it. The assessment was intended to provide a broad framework of information that would facilitate the planning of the future generation expansion programme. One of the reasons for undertaking SEPR was to respond to a June 1976 report of the Ontario Legislature's Select Committee on Ontario Hydro Affairs, which recommended the adoption of a revised generation programme with a reduced target for additional generating capacity, after the implementation of load-management and conservation programmes.[5]

The purpose of the SEPR study was to estimate the socio-economic effects on the Ontario community of various hypothetical generation expansion programmes for the period 1978-97 and to examine the relationships between the growing demand for electricity, the mix of nuclear and coal-fired generating capacity, the size of the generating units, the reliability of electricity supply, and the cost, availability, and security of fuel supplies, on the one hand, and financing requirements and capital availability, the cost of electric power, and socio-economic and environmental conditions, on the other hand.

The SEPR study represents an important step in the evolution of Ontario Hydro's planning process. It is basically an evaluation of many possible generation expansion programmes as responses to two possible demand growth rates. The study is one of several possible methodological approaches to the issues studied. Every approach has certain strengths and weaknesses. The major strength of the SEPR work is its detailed analysis of the reliability, cost, and broad economic impact of the generation-load

scenarios studied. Its principal weakness is the fact that the generation expansion programme to be evaluated is specified at the outset and is not modified even if it becomes clear that it would have an adverse economic impact on society. Thus, the methodology is a good one for evaluating a set of generation programmes but not for selecting a generation expansion programme based on given system design criteria.

An assumption fundamental to the study's evaluation framework is that a specific predetermined generation expansion programme will be followed throughout the study period no matter how low the system reliability falls or how large the costs of power become. Thus, none of the adaptive possibilities of the programmes, as normally implemented, is incorporated in the study. Moreover, except for a new and important approach to reliability, no uncertainty was incorporated into any element of the results. It should be emphasized that this type of study is an important improvement in the methodology used earlier and should be regarded as a first step along an important new path.[6]

The study considers variations in the generation expansion programme for only two load-growth rates – 6.4 per cent and 5.5 per cent average annual growth. All variations assume the completion of the committed generation expansion programme, including the Darlington Generating Station. The variations in the uncommitted generation programme consist of three levels of mix of coal-fired and nuclear generation – high nuclear (2 nuclear to 1 coal), low nuclear (1 nuclear to 2 coal), and no nuclear (i.e., all coal); two levels of base-load generating unit size – 850 MW and 1,200 MW; and five levels of target generation reserve – 15, 20, 25, 30, and 35 per cent. The study did not consider variations in transmission and distribution expansion, the location or dispersion of generation, or generating units of smaller sizes. Since the study was initiated late in 1976 (released in February 1979), the load forecasts have dropped well below the lowest growth rate considered in the project. Thus, the methodology and general nature of the results are the only aspects that are still relevant.

The methodology consists of two stages. First, judgement is used to select a set of generation expansion programmes in accordance with different assumptions about the external environment. The generation programmes are characterized by a constant reserve margin, a constant mix of coal and nuclear units, and a given size of base-load units over a 20-year period (from 1978 to 1997). The growth of demand is the only major external condition that varies. This choice of expansion plans determines the results of the "what if" type of question. For example, the choice of 850 MW coal-fired units as the means of varying the reserve margin determines the incremental cost of reserve (that is, the slope of the "expenditure" line in Figure 4.5 in Chapter 4). Moreover, although this type of study computes the cost of power for different generation programmes, it does not allow that cost to affect the growth of demand and thus the associated generation programme. Similarly, this approach does not allow the reserve margin associated with an expansion programme to be increased, even if the reliability is decreasing.

The second aspect of the methodology is that, for each expansion programme, various system performance characteristics such as cost, reliability, and socio-economic impact are computed for each state of the external environment (in this case the two levels of demand growth). The generation scenarios were analysed in three phases. In Phase I, fuel requirements, long-run costs, revenue requirements (cost of power), and borrowing requirements were computed. In Phase II the study focused on the question of reliability. (This is described in detail in Chapter 4.) In Phase III, various judgemental modifications to an econometric model were used to estimate for each load-growth rate the relative effects of each generation programme on major economic indicators such as economic growth, inflation, employment, balance of payments, and the Canadian dollar exchange rate. In addition, Phase III estimated the relative manpower requirements, the effects of a programme change on supply and export industries, and the effect of higher electricity costs faced by some industries.

The results fall into three categories: the effect of the rate of growth of demand, the effect of the mix of generating types, and assessment of the appropriate reliability standards. For example, if the demand growth rate is less than 5.5 per cent (as Ontario Hydro's 1979 load forecast suggests), no critical fuel supply or financing problems are envisaged. The results also indicate that if the load growth is sufficient to warrant new installations, a programme with about ⅔ nuclear capacity will give both the lowest long-run costs and the lowest cost of power. It is important to note that the present value of economic costs becomes less and less sensitive to the mix chosen for the expansion programme as the rate of growth of demand drops. For example, the extra economic costs of a no-nuclear programme over a high-nuclear programme (both with a 25 per cent reserve margin) with a 5.5 per cent annual growth of demand are

less than half the extra economic costs with a 6.4 per cent annual growth. Note also that while a higher-nuclear programme is somewhat lower in economic cost than the other programmes, it requires more capital and so may result in a somewhat higher retail cost of power until the growing fuel cost savings outweigh the increased capital requirements. The results of the econometric model suggest that a reduction in the role of nuclear plants in the generation mix leads, for the most part, to lower investment in Canada and in Ontario. The new approach to balancing the costs and benefits of reliability indicates that the traditional LOLP calculation gives a reserve margin level (about 30 per cent) that is a few percentage points higher than the new estimates (see Chapter 4).

Phase III of SEPR also analysed the economic potential of industrial co-generation in Ontario. The results suggest that if the system were expanded at the lowest reserve margin considered (that is, 15 per cent), the economically and technically justifiable co-generation capacity in 1985 would be about 1,100 MW. At higher system reserve levels, the economic potential would drop to 600 MW.[7]

The main thrust of innovation in the SEPR study was its attempt to be much more inclusive than methodologies used previously. There are two main new features. The first is the treatment of reliability in terms of balancing the benefits to the customer of a given reliability level with the costs imposed on the customer by the utility for supplying that level of reliability (see Chapter 4). The second is the attempt to estimate, for each demand growth rate, the indirect economic effects arising from the generation expansion programme. The focus of this work was the development of econometric models to reflect Ontario Hydro's system expansion and borrowing activities. First, models of the Canadian and Ontario economies were modified so that capital expenditures, domestic and foreign borrowing, and the price of electricity could be entered as independent variables. Second, the Ontario model was extended by adding information from the 1965 Input-Output Table for the province, to measure the output of Ontario industries. Next, forecasts for Canada and Ontario for the period 1978 to 1997 were developed for the reference case associated with each load-growth alternative. Then a number of simulations were made by using different sets of data, reflecting variations in system expansion programmes. The direction and magnitude of the changes in important economic variables were then used to provide an indication of the nature of changes in the economic environment.

As Ontario Hydro has stated, SEPR is only one component of Ontario Hydro's changing planning process, and it does not address all the factors that must be considered in system design. Some aspects of SEPR that limit its application to system design have been identified. These aspects will be discussed, in a review of the possibilities for future related work.

The first point is that the characteristics of the generation programmes studied *vis-à-vis* each load-growth projection were fixed at the outset and were not allowed to vary with time. The reliability implications of such an assumption were discussed in Chapter 4. Concerning the generating mix implications, while the methodology permits the evaluation of various long-term generating mixes, it does not, for example, determine the effect on generating mix of changes in various planning factors, such as load growth, capital availability, and fuel supply.

The second point is that uncertainty is not analysed in the strategic sense. For example, the study assumes that demand uncertainty affects the reliability of the system, but not the choice of a generation programme or fuel supply. The portion of the SEPR study that deals with reliability makes the important point that in the presence of uncertainty, unless losses on one side of the average value are balanced by gains on the other side, the average outcome may be misleading. The other areas of the study do not recognize this issue, although much uncertainty is clearly present in the estimates used. For example, in the lower load-growth case, the study concludes that, while all generation alternatives are financially viable, there are increased risks of capital availability constraints on the high-nuclear alternatives. Similarly, the study concludes that while a no-nuclear option after Darlington is viable under the lower load-growth assumption, there would be increasing coal-supply uncertainty. We believe that in subsequent studies considerable analytical work should be devoted to the problem of choosing the best expansion programme in the context of explicit representation of the most important uncertainties.

The third limiting aspect of the study, as discussed earlier, is that neither changes in the cost of power nor changes in the reliability levels over time affect the demand for electricity and thus the associated generation programmes.

Ontario Hydro's Current Generation Expansion Programme

Following its review of the generation expansion programme in 1978 (Program Z) and faced with a further sharp reduction in the load forecast, Ontario Hydro undertook another review of the generation programme in 1979.[8]

In the 1979 load forecast, the average annual rate of load growth to the year 2000 is approximately 4.5 per cent, compared with 5.4 per cent in the 1978 load forecast. The forecast total system January primary peak in the winter of 2000-01 is 43,031 MW – the peak in 1978-9 was 16,252 MW. Two other considerations characterize the latest review. It incorporates the conclusions of Ontario Hydro's System Expansion Program Reassessment (SEPR) study with respect to reliability and generating mix (see the preceding section). The review also includes, as part of the long-range plan, a further development of hydraulic capacity which is a proportion of the approximately 2,000 MW hydraulic development programme approved by Ontario Hydro's Board of Directors in July 1978.

The long-term generating-mix assumptions are basically the same as those used in the previous generation forecasts except for the inclusion of about 1,100 MW of peak- and intermediate-load hydraulic development in the 1990s, as mentioned. For the forecast loads, approximately three-fourths of the capacity additions beyond Darlington are nuclear.

Load management is included in the programme to reduce the primary peak loads. The load-management targets, estimated in a study carried out by Ontario Hydro's Energy Conservation Division in July 1978 (see Chapter 8), are used to determine the managed firm peak load, which is the basis of generation planning. The targets are 500 MW in 1985, 1,300 MW in 1992, and presumably about 2,000 MW in 2000. The managed firm peak load is obtained by deducting these load-management targets, as well as approximately 500 MW of interruptible loads and 178 MW of the Bruce Heavy Water Plant electrical load, from the primary peak load.

The standard of reliability used in the 1979 review is lower than Ontario Hydro's previous practice of a loss-of-load probability (LOLP) of one day in 10 years. The SEPR study concluded that the "planning standard for generation reliability can be reduced without undue risk to the quality of service, provided adequate transmission capacity is available."[9] Consequently, Ontario Hydro has used a new reliability criterion of 10 system minutes of unsupplied energy per year, based on the "frequency and duration of outages" method (see Chapter 4). This includes reliance on emergency support of 500-700 MW from interconnections with the neighbouring systems. In calculating the expected unsupplied energy, explicit account is taken of an assumed 2.7 per cent load reduction to be achieved by a 5 per cent reduction in supply voltage.

The new criterion results in reserve requirements of approximately 23-25 per cent relative to the managed firm peak or 15-17 per cent relative to the primary peak. This compares with the 27-30 per cent reserve margin standard (relative to the primary peak) used previously. Thus, the net effect of load management, of reliance on interconnections, and of equating costs and benefits of reliability is a reduction in the generating reserve margin of approximately 12-13 per cent.

Another noteworthy change in generation-planning methodology evident from the 1979 review is the joint planning of Ontario Hydro's East System and West System. The planning assumes a high-capacity interconnection between the two systems by the late 1980s or early 1990s. However, the capacity and the nature (AC or DC) of the interconnection are not discussed.

After reviewing several alternatives, the Ontario Hydro Board of Directors adopted, for the committed generating stations, the programme shown in Table 7.2. The in-service dates of the Thunder Bay Generating Station and of Pickering B remain unchanged, i.e., as they were in Program Z. A decision to stop the construction of the Wesleyville Generating Station and store it until 1990 was taken in February 1979. Atikokan units 1 and 2 have been postponed by one and four years, respectively. Bruce units 5 and 6 remain on schedule but units 7 and 8 are postponed by one year. Completion of the first two units at Darlington has been extended by 18 months and of the last two units by 30 months, from the original schedule in Program Z. Table 7.3 shows the mix of capacity of the existing and committed generating resources as well as of the additional uncommitted programme to 2000, under the 1979 load forecast and two lower-growth scenarios (4 per cent and 3 per cent). For the uncommitted programme, the specifics of unit size, in-service dates, and sites are not discussed. Ontario Hydro's position is that these "are the subject of detailed study before any recommendation is made for the commitment of new generating capacity". As was the case with the earlier long-range generation forecasts (Table 7.1), the share of nuclear in the total system capacity for the 1979 forecast load is about 50 per cent by the end

Fig. 7.3: p. 94
Fig. 7.4: p. 95

of this century. Figures 7.3 and 7.4 show the annual fuel consumption and contracted supply for uranium and fossil fuels, respectively. Also shown are estimates of fuel consumption under a 3 per cent load-growth rate, which will be discussed in the next section. The fuel consumption estimates are based on the fact that because of their lower fuel or operating costs, the available nuclear and hydraulic resources will be utilized to the fullest extent possible before fossil fuels are used.

Table 7.2 Ontario Hydro's Committed Generation Programme

			In-service date										
Station	**Size (MW)**	**Fuel type**	**1980**	**1981**	**1982**	**1983**	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**
Thunder Bay	2 × 149	lignite	1	1									
Pickering-B	4 × 516	nuclear	–	1	2	1							
Bruce-B	4 × 756	nuclear	–	–	–	1	1	–	1	1			
Atikokan	2 × 206	lignite	–	–	–	–	1	–	–	–	1		
Darlington	4 × 881	nuclear	–	–	–	–	–	–	–	1	1	1	1
Wesleyville	2 × 541	oil	–	–	–	–	–	–	–	–	–	–	2

Source: RCEPP.

Table 7.3 Ontario Hydro's Generation Programme to the Year 2000

	Committed (MW)	**Load growth projection Uncommitted (MW)**		
		1979 load forecast [a]	**4%**	**3%**
Nuclear	13,860	11,450	6,800	0
Fossil[b]	14,855	2,750	0	0
Hydro	6,515	1,100	1,100	600
Total	35,230	15,300	7,900	600
Total generating capacity in 2000		50,530	43,130	35,830

Notes:
a) Approximately 4.5 per cent.
b) Uncommitted fossil is all coal.
Source: RCEPP.

Implications of Low Load Growth

In its "1979 Review of Generation Expansion Program", Ontario Hydro raised concerns about the implications of a load-growth rate lower than their 1979 load forecast. These concerns relate to the cutbacks in the delivery of fossil fuels in the 1980s and the likely impact on the nuclear supply industry of delaying uncommitted nuclear capacity. These concerns will be discussed here under the assumptions of a 3 per cent annual load-growth rate. If Hydro's primary peak load were to grow at an average annual rate of 3 per cent, the primary peak in the winter of 2000-01 would be 31,140 MW. As shown in Table 7.3, the total dependable peak capacity of Ontario Hydro's existing and committed programme is 35,230 MW, and at a 3 per cent load-growth rate the uncommitted programme calls for no new fossil or nuclear capacity and only 600 MW of hydraulic development to the year 2000.

Ontario Hydro's concerns relating to the cutbacks in the delivery of fossil fuels arise from the growing disparity between the contracted supply levels of fossil fuels and their projected utilization under a 3 per cent load forecast assumption:[10]

> A reduction to a low load forecast of 3 per cent would result in severe cutbacks in delivery of U.S. bituminous coals in the short term along with reductions in Canadian coal deliveries in the years 1982 to 1989. These cutbacks in deliveries over an extended period would result in a substantial increase in the unit cost of fuel through penalties for non-delivery and anticipated increases in unit coal prices.
>
> In the extreme scenarios with unmodified generation programs and with 3 per cent load growth, fossil fuel requirements decline to virtually zero in the late 1980s with consequent severe contract penalties and impairment of generation diversity.

Ontario Hydro's concerns are well founded, but the problem of cutbacks in the U.S. coal deliveries will exist until the mid 1980s even with the current load forecast of approximately 4.5 per cent (Figure 7.4). Of the approximately 10 million tonnes of fossil fuels that will be required annually during the first half of the decade, the share of residual oil, natural gas, and western Canadian coal is about 3.6 million

tonnes. The remaining 6.4 million tonnes, to be supplied from the U.S. markets, is only 65 per cent of the contracted U.S. supplies and thus represents a 35 per cent cutback.

With a load-growth projection of 3 per cent, the fossil fuel utilization will indeed decline to virtually zero by 1990 if the committed programme is not modified in response to the lower loads (Figure 7.4). Such a scenario appears to be unrealistic. If the load were forecast to grow at 3 per cent, some committed capacity would be deferred – most likely Darlington and probably Bruce units 7 and 8. Even if units 7 and 8 are completed on the current schedule (1986-7), the availability of the full 6,000 MW output of the Bruce complex is in doubt due to the uncertainty associated with the second 500 kV line out of Bruce. This uncertainty was noted by Ontario Hydro in its 1979 review:[11]

> It is foreseen that a lengthy public participation and review process will be required to establish the need, the plan, and the route and site location for a second 500 kV line from Bruce. The earliest in-service date for this line is estimated to be late 1986. However, it is expected that there will be considerable opposition to this line from segments of the public in southwestern Ontario and the in-service date could be significantly later.

The Commission, which had been asked to investigate the need for additional bulk power facilities in southwestern Ontario, recommended in its report to the Minister of Energy in June 1979 that:[12]

> Because we foresee serious social as well as environmental and economic problems associated with the possible construction of a second 500 kV line from Bruce following any route that crosses the prime foodlands of Ontario, all other alternatives . . . even if there are apparent economic penalties, should be explored fully before further consideration is given to such a proposal.

On the issue of deferring units 7 and 8 of Bruce B in case the second 500 kV line is not in service by 1986, the Commission observed: "There is probably little advantage in completing them before the second 500 kV line is available."[13]

If load growth is an important consideration in the determination of the timing of the second 500 kV line out of Bruce, a 3 per cent load forecast will tend to delay it.

We consider two scenarios involving deferrals in the committed programme (Figure 7.4). The one with the lower fossil-fuel requirement assumes the deferral of Darlington by three years from its current schedule (1987-90), whereas the one with the higher requirement assumes the deferral of Bruce units 7 and 8 by three years and Darlington by six years. Even in the second case, it will be possible to maintain a 25 per cent generating reserve margin until the late 1990s. As may be seen from Figure 7.4, deferring Darlington by three years increases the fossil-fuel consumption significantly in the late 1980s and the early 1990s, and this consumption exceeds the contracted amount in 1989. By deferring both Bruce and Darlington, the consumption exceeds the contract levels in 1987 and after that it averages the level implied by the 1979 load forecast. After the completion of the committed programme, the fossil-fuel requirements under the 3 per cent scenarios increase rapidly, and exceed the 1979 load forecast levels by the late 1990s.

Our overall conclusion based on this analysis is that a reduction in load forecast to 3 per cent will not increase the severity of impact on coal supplies to the extent predicted by Ontario Hydro. As far as surpluses in the early 1980s are concerned, Hydro's efforts to export excess power and energy are encouraging. The latest estimate of export sales in 1979 is 12 TW·h, up from 10.4 TW·h in 1978 and 8.4 TW·h in 1977. The sales represent approximately 4 million tonnes of U.S. bituminous coal.

Figure 7.3 shows the estimated annual uranium consumption corresponding to the three scenarios under the 3 per cent load-growth assumption. It is evident that considerable uranium oversupply will develop under all the 3 per cent growth rate scenarios if the contracts are not changed in response to lower demands. Due to the nature of the uranium supply contracts and the relative ease of storage, shortages appear to present much greater risks than surpluses.

Concerning the nuclear supply industry, Ontario Hydro has expressed concern that any generation programme corresponding to the "1979 [load] forecast [will] have very serious consequences for Ontario Hydro suppliers of equipment and services," and that "should the 1979 load growth projections be optimistic and further delays of the nuclear programme be required, there is a real risk of losing valuable and necessary technology and expertise".[14] The Commission presented its views on this issue, which is outside the scope of this volume, in its *Interim Report on Nuclear Power in Ontario* and discusses it further in Volume 1 of this Report.

Planning Bulk Power Transmission

The process of planning electric power for Ontario has been treated up to this point in global terms, that is, as the matching of power generation to load growth. The question of interconnecting generation with load remains to be considered. In order to be supplied properly, new loads must be connected effectively to the power network and through it to new generating facilities. It is to be expected that the existing power network may be unable to transport the increased amount of energy and that the network will therefore have to be expanded. Alternative expansion schemes must be considered and the best one selected. Expansion of the part of a network that interconnects major load centres with major generating sites is the concern of what is called bulk power transmission planning.

First, the general nature of bulk power transmission planning will be considered briefly. Then the planning process pursued by Ontario Hydro will be examined, and, finally, there will be a brief look into the future of bulk power transmission in Ontario. In the last portion of the discussion, issues related to the topic will be discussed and an attempt made to identify concepts that are likely to be useful in the future planning of the transmission network.

General Approach

The bulk power network in Ontario is an extensive one, and it connects many load centres with many generating stations. The gradual growth in load as well as the creation of new load centres must be matched by the addition of new generating units or the development of new generating sites, and the capability of the bulk transmission network to accommodate the added flow of power must also be considered.

In the planning of an expansion of the network, several often competing requirements must be satisfied. First, the transmission system must be highly reliable. The added load and the added generation must be so integrated that the reliability of the system does not deteriorate. Second, the expanded network must have acceptable security. Third, the selected plan must be as efficient as possible, so that the transport of power is accomplished with an acceptable energy loss. And, finally, the expanded network must be cost-effective and its environmental impact must be minimal.

A detailed study of each plan is required, to satisfy the enumerated requirements. Consequently, the planning process must commence with the identification of suitable alternatives. In most cases at present, the initial choice is made on the basis of human judgement. The previous experience of the planner can therefore be a great asset in this phase of the planning process. Once acceptable alternatives have been identified, the evaluation of each alternative may be undertaken by a more structured procedure, involving use of a computer.

The evaluation phase involves several stages. Of these, the technical evaluation can be performed adequately by a computer. The power system in Ontario is interconnected with those of its southern and western neighbours, and for that reason the operating criteria of the interconnected systems must be compatible. Appropriate design criteria for the security and reliability of the network were developed by the Northeast Power Coordinating Council (NPCC), of which Ontario Hydro is a member. According to these criteria, the power system of each member must, for instance, be able to maintain stability when one transmission circuit is out of service (e.g., for maintenance) and, at the same time, a transmission line (with either one or two circuits) is lost perhaps because of a storm. Each proposed alternative for expansion of the transmission network must comply with these requirements. Questions of resulting line flows and of possible overloadings are readily answered by computer studies performed for each specified set of operating situations. After the technical feasibility has been established, the economics of each proposal is evaluated, and, finally, the impact upon environment is assessed.

Now the stage is set for a meaningful comparison of the alternatives. A considerable amount of human judgement inevitably enters this task, because comparisons must be made between quantities that have distinctly different qualities. Yet this is one of the most important stages of the planning process. Its results establish which of the alternative expansion schemes should be adopted.

Ontario Hydro's Approach

In June 1976, Ontario Hydro submitted to the Commission a memorandum describing its transmission planning process.[15] When planning the development of its bulk power transmission network, Hydro divides the process into four main steps:

- determination of the additional facilities required, and their timing

- development of alternative systems capable of meeting specified requirements
- evaluation of the alternatives
- selection of the alternative to be recommended

Ontario Hydro considers it necessary, to reduce the overall costs and increase the reliability, that the selected alternative be compatible with its long-range plans.

The first step is taken upon completion of the generation planning process, in which the size and location of new generation facilities, as well as the timing of their completion, were determined. The purpose of this step is, therefore, to answer the question, whether existing bulk transmission facilities are adequate for the purpose or whether additional facilities will be required. Expected loading patterns are developed and the operation of the whole system is tested on the basis of specified reliability and security criteria.

The experience of Ontario Hydro indicates that it takes at least eight years to build a major transmission line. The actual construction work may take only two years, and at least two more years are required before that, for making the detailed design, acquiring the needed right of way, and preparing for the construction phase. Before any of this can take place, however, at least four years will have been spent on developing plans for alternate routes, arranging for public participation in the selection of acceptable alternatives, and obtaining government approval of the final choice.

To arrive at a number of feasible alternatives is the goal of the second step in Ontario Hydro's bulk power transmission planning process. There may be a number of ways in which the existing system can be expanded to satisfy the requirements of the assumed load growth and of the pattern of additional generation. These alternatives may range from the simple rearrangement of connections in the existing network to the construction of completely new transmission lines and station facilities. They may involve increasing the rating of lines, upgrading the power transfer capability of existing rights of way, installing series or shunt capacitors and reactors, establishing new interconnections with neighbouring utilities, and developing facilities for the rejection of generation or of load.

The planner must exercise a considerable amount of judgement in drawing up a list of acceptable alternatives. To be considered acceptable, a plan must be technically sound. This can be determined quite rationally because the technical performance of a system can be quantified. Also, the level of reliability of a plan that is under consideration must be acceptable. It must be ascertained that the system would operate under normal and emergency conditions within acceptable thermal limits and within the prescribed voltage range. Short-circuit limits and stability requirements must also be met.

However, a plan that is technically feasible may have to be rejected because of socio-environmental considerations. Computer assistance is sought where suitable at this stage. Ontario Hydro has developed an elaborate computer-aided approach to help the planner evaluate the environmental, demographic, and socio-economic impacts of a projected transmission route. In this approach, the information about the region in question is stored in a computer on the basis of a 2 km by 2 km grid. Each square is then classified with respect to nine "factors" – human settlement, agricultural production, timber production, mineral extraction, wildlife game resources, recreation, aquatic communities, terrestrial communities, and the appearance of the landscape. Each factor is further divided into a number of "objectives". For example, the factor "agricultural production" is divided into eight objectives, such as areas producing fruit, vegetables, and tobacco, areas with a very high concentration of common field crops, areas with a low concentration of common field crops, class I or II soils officially designated for future residential, commercial or industrial use, etc. A total of 49 such objectives are then placed in order of their importance with respect to selecting a route. For example, existing urban and non-urban areas of human settlement are at the top of the list and must be avoided. With this information base in the computer, the planner can make rational decisions about the impact of any proposed routing. A composite map can also be produced, enabling the planner to see how routes of significantly undesirable impact can be avoided.

When the planner has identified a plan that has a high probability of satisfying the many varied requirements for the expansion of the transmission system, a detailed evaluation of that plan is undertaken, involving the compilation of environmental data, cost data, and technical data. These background data are put to use in the final step, which is the selection of the "best" alternative. The environmental information includes details about ecological impact, land productivity, and the probable effect on human environment of each feasible plan; these details are considerably more extensive than those used in the computer-assisted assessment mentioned above. As for cost data, the effects of capital cost,

operating expenses, and the cost of transmission losses and maintenance are included. To remain in the running, a plan must meet certain minimum technical requirements. But every plan has a somewhat different impact upon such factors as reliability, ease of operation, and ability to adapt to variations in the economic conditions of the province. Some alternatives may be more adaptable, for instance, to changes in the load forecast. All these factors are taken into account by Ontario Hydro when it decides to accept a particular proposal for the expansion of its bulk power transmission systems.

Planning for the Future

The preceding discussion provides some idea of the process of bulk transmission planning, as background for an examination of some of the important issues in the planning process. Discussion of the expansion of the bulk transmission facilities in Ontario cannot be limited to a consideration of load growth and new generation. The planned retirement of outdated generating plants and the replacement of old bulk transmission facilities must also be considered. Additional lines may be needed, not only because of expected growth in load but also to replace obsolete transmission equipment. Replacement of obsolete generation plants will not affect the extent of required transmission facilities, but it may indicate a need to change the configuration of the bulk transmission network, should the replacement generation be at a different site.

The strategy for developing bulk power transmission is roughly similar to the principle used for the installation of a local distribution system. It is easy to see why, in a row of houses in a subdivision, an electricity supply configuration in the form of a mesh is greatly preferable to a radial system. With a mesh, the row of houses is supplied from both ends, while in a radial system, it is supplied only at one end. When a fault occurs along the feeder, in a radial system, service is interrupted to all houses that are located beyond the fault. Security of supply is, therefore low. When the same row of houses is supplied from both ends, the occurrence of the fault can only cause an interruption of supply to one house, at the most. Thus, the security of supply is much greater.

The experience with distribution systems may be applied directly to the bulk transmission system. The main difference is that security criteria for the transmission system must be much higher than those for a distribution system, because far more customers are relying on the transmission network. Indeed, some loads are so critical that they may not be left without supply under any circumstances. Hospitals, for instance, are in that class; for them, in addition to providing a supply of high security, an emergency generator, usually with a diesel engine as the prime-mover, is installed on the premises.

To create a bulk power transmission system of very high security for a region, the same mesh concept that is used for local distribution is applied, on a larger scale. Each load centre, such as a city, is supplied from at least two generating sites, and the bulk transmission system is so designed that power converges on the city from geographically opposite ends. The generating sites are also connected directly with one another, so that this part of the bulk power network has the shape of a triangle. Power can be delivered to the city from both generating sites during a fault on any side of the triangle.

An example of this approach is provided by the bulk power transmission systems in southwestern Ontario and eastern Ontario.[16] In southwestern Ontario, the planning of the bulk power transmission system must meet three basic objectives: to supply the growing loads in the region, particularly in the London, Sarnia, and Windsor areas; to incorporate Bruce B into the bulk power grid; and to strengthen the transmission system so as to facilitate the mutually beneficial interchange of power with U.S. utilities. The expected growth of the load in the region will, if realized, require additional transmission facilities in the 1990s. The simplest way to satisfy the three aforementioned objectives would be to construct one 500 kV line to London from the Bruce generating complex and another from the Middleport Transformer Station near Nanticoke. A triangle of the 500 kV grid would thus be constructed in southwestern Ontario, the third leg being the 500 kV line from Bruce to Milton and down to Middleport and Nanticoke. A detailed study of this proposition reveals a possibility of achieving the stated aim while eliminating the need for part of the right of way that would otherwise be required. The saving may be accomplished by taking down one of the three parallel 230 kV circuits between Middleport and London and utilizing its right of way for the new 500 kV line. The possible scenario may be described as follows.

First, a 500 kV line would be constructed to reach London from the north and supply London with electricity generated at Bruce. Then the loading on the two 230 kV lines from Middleport to London would be decreased to the extent that one of their three circuits could be taken out of service for several years without detriment to the supply. At this stage the single-circuit 230 kV line would be pulled down

and a 500 kV circuit erected on its right of way. The timing of the changeover would be extremely important. Conversion would have to be completed before the load in the London area increased to the extent that the security of supply would be contingent on the 500 kV circuit from Middleport.

It is emphasized that serious social and environmental concerns are associated with the possible construction of a second 500 kV line from Bruce over prime foodlands. These concerns must be resolved before such a proposal is adopted. The Commission underlined these concerns in June 1979 in its *Report on the Need for Additional Bulk Power Facilities in Southwestern Ontario.*

In eastern Ontario, the immediate and most important consideration in the planning of the bulk power transmission system is the supply to the Ottawa area. Because of transmission deficiency, automatic reactive power devices will have to be depended on in the 1980s to maintain voltages in the Ottawa area at acceptable levels following any failure in the bulk power transmission system. The level of load that could be supplied will be exceeded in the early 1980s under any annual rate of load growth in excess of 3 per cent. The planning of additional bulk power transmission facilities in eastern Ontario is therefore a matter of urgency. The Commission recommended the continuation of the planning process, in July 1979 in its *Report on the Need for Additional Bulk Power Facilities in Eastern Ontario.*

One of the most technically attractive ways of supplying Ottawa by means of the existing generating resources, using the triangle concept, is to construct a triangle of 500 kV lines with Ottawa, the Lennox Generating Station near Kingston, and the Saunders Generating Station near Cornwall as the three vertices. This would ensure the supply to Ottawa from two major generating stations and strengthen the bulk power grid in eastern Ontario in a way that would facilitate mutually beneficial interchanges of power with Quebec and New York. As in the case of the projected 500 kV line in southwestern Ontario, it is emphasized, all other alternatives must be explored fully.

At the present time, human judgement constitutes a very important component in the decision process for new bulk power transmission components. This means human participation in the process, which is desirable, since planning involves the use of innovative ideas and should not be completely delegated to a computer. However, there are many steps in the development of background arguments for the decision-making process that can and should rightly be carried out, in our age, by a computer.

One of the tasks that may be usefully performed by a computer is the testing for security of an expansion alternative. The process of arriving at this information is usually referred to as the "contingency analysis", and it is at present still an immature area of power system studies. In this approach, many calculations must be made to determine what operating situations might cause an overloading of a given transmission system. In the case of Ontario Hydro, such a study may involve hundreds of load-flow solutions for each plan being considered, and the practice up to now has been to allow human judgement to intervene at this stage of the planning process. However, the present trend in system studies is directed towards the development of very fast, although approximate, computer techniques to establish the effects of changes in the transmission network upon the associated distribution of power flows. The results are not exact, but they are accurate enough to indicate when a proposal for network expansion should be rejected. Such computer approaches are expected to become available in the near future as an aid to the system designer in selecting expansion alternatives that should be studied in more detail.

Something that is lacking at present in the process of planning bulk power transmission is a systematic approach to the problem of weighing the technical aspects of a plan against the environmental considerations. At present, responses to questions of the environment tend to be emotional, whether pro or con. But there would be no need for this if it became possible to make rational comparisons. What is needed is an approach that would provide a meaningful assessment of the environment impact and thereby permit a comparison of technically feasible alternatives. Ontario Hydro's factor map is an important step in this direction.

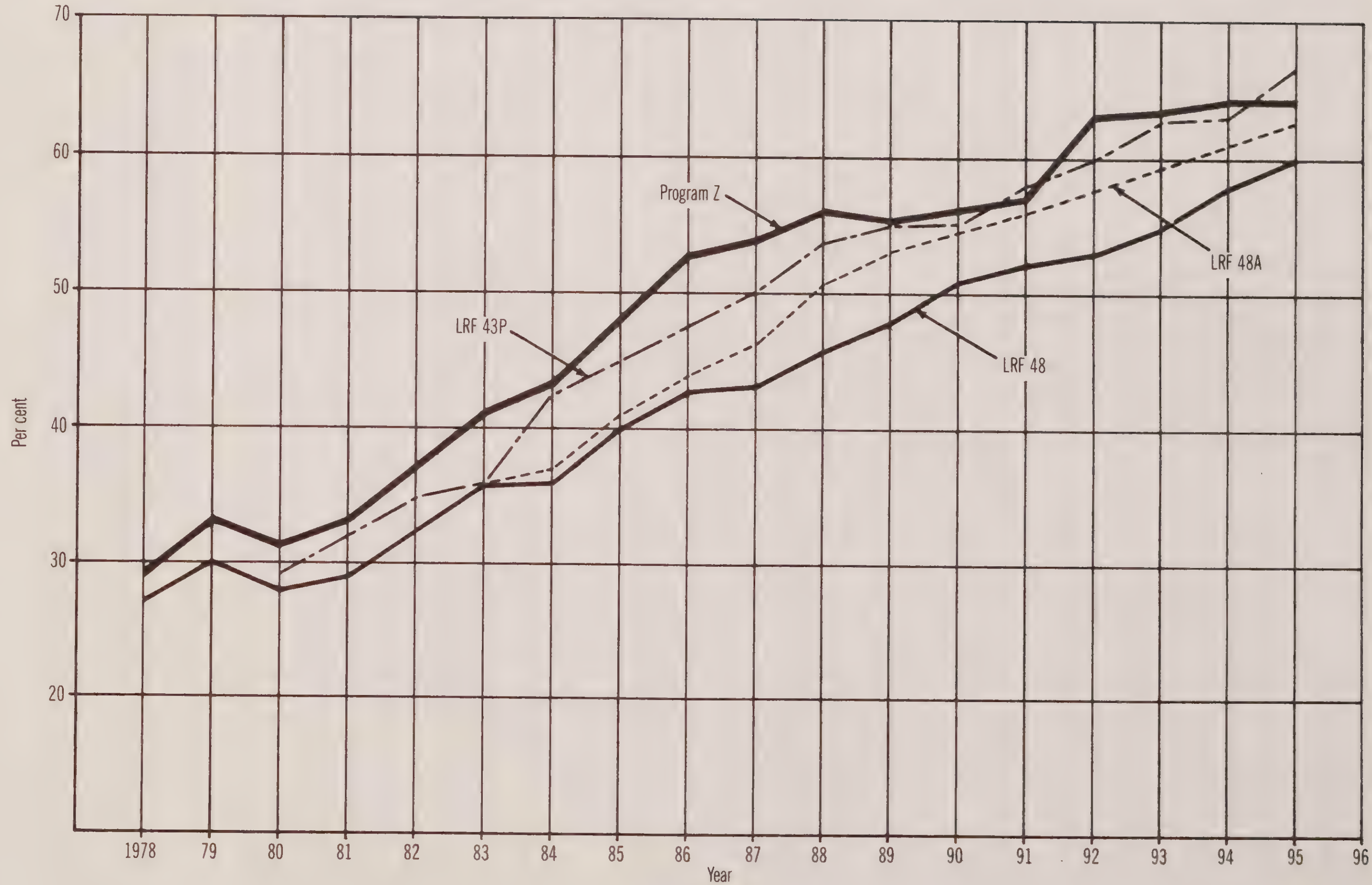
Concerning the stop-gap measures proposed by Ontario Hydro[17] for upgrading the bulk power transmission network, these often constitute an economically viable and ecologically attractive way to cope with the expansion of load and generation in Ontario. Nevertheless, care should be taken in each case to ascertain that the proposed solution is the best one. While effective in the short term, a solution may turn out to be less than desirable in the long run. The upgrading of the current-carrying capacity of some of the 115 and 230 kV lines in Ontario is a case in point. Such an approach would help to postpone the need for the 500 kV network in southwestern Ontario by loading the existing lower voltage circuits to the fullest. At the same time, such a choice would lessen the flexibility of planning the transmission

system. In the case of the eastern Ontario system, for example, it would preclude a later conversion of 115 kV lines to 230 kV.

Another matter that should be considered in connection with the bulk power transmission in Ontario is high-voltage direct-current (HVDC) transmission. To date, there has been no need for any HVDC facilities in the province, but this situation may change, for two reasons. The first has to do with the fact that HVDC is cheaper than high-voltage alternating current (HVAC) transmission over great distances (see Chapter 2). Consequently, if there is a need to develop remote generating sites or to interconnect systems at great distances, the HVDC alternative becomes attractive. Secondly, improvements in solid-state terminal equipment for HVDC systems mean that the cost of HVDC terminal stations is dropping steadily and the break-even point between the HVDC and HVAC is moving towards smaller and smaller distances. At present, the break-even distance is about 650-800 km.[18]

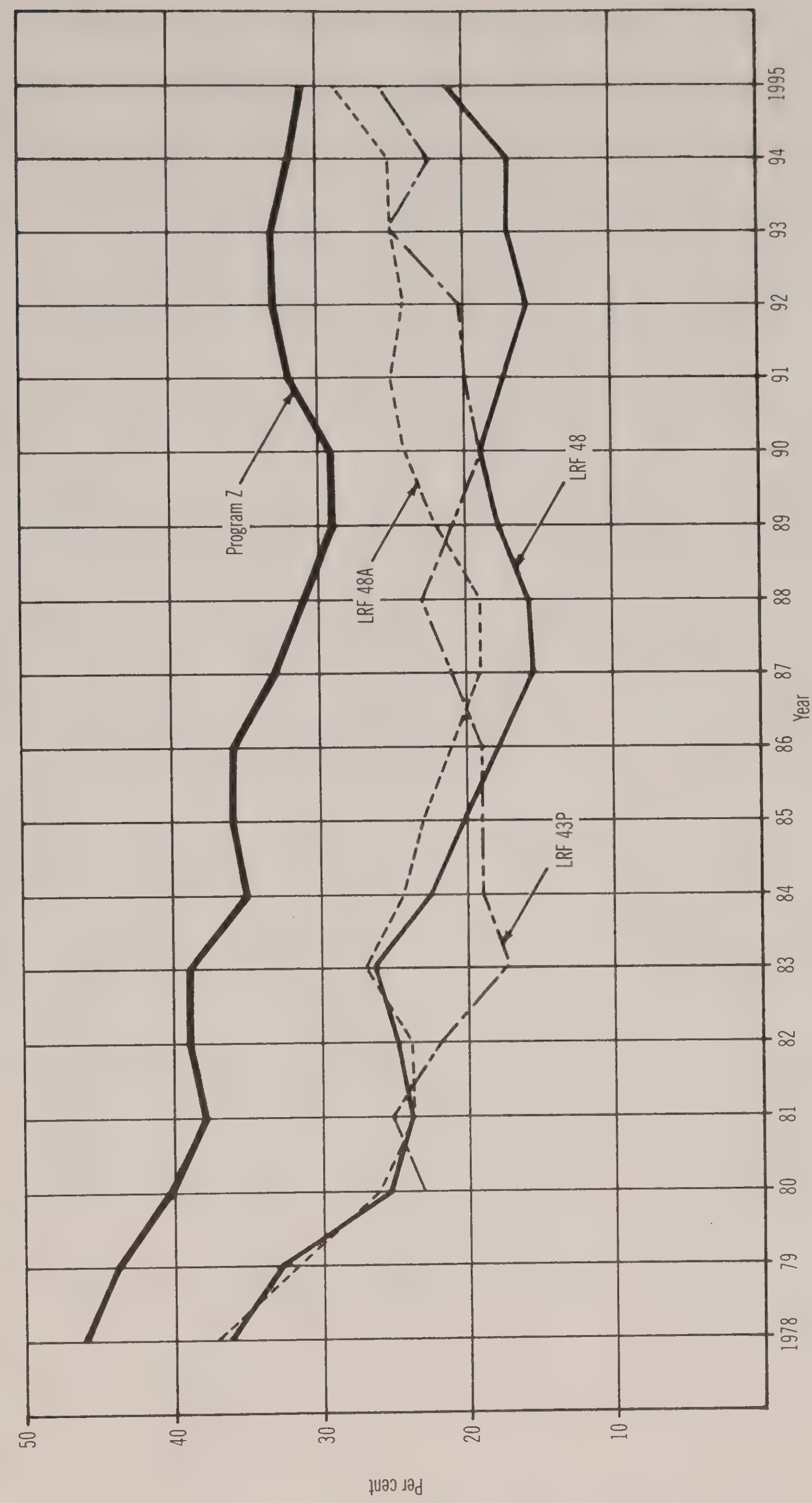
There are three possible future uses for HVDC transmission in Ontario. One of these is an interconnection between Ontario Hydro's East System and West System and between the West System and Manitoba. Manitoba has the potential for further development of its hydraulic generation sites on the Nelson River. For that reason, Manitoba might become interested in an interconnection with Ontario. Such an interconnection would also be of benefit to Ontario Hydro, since it would strengthen its bulk power grid in northwestern Ontario and provide a strong interconnection with a neighbouring province. Another possible application of HVDC may be envisaged in connection with the development of the lignite deposits in the Onakawana basin in northern Ontario. The distance to the closest significant load – Sudbury – is about 500 km, and it is another 400 km to Toronto. There is little settlement along the route, which is a desirable situation for point-to-point HVDC transmission. Ontario Hydro is seriously considering the construction of a 1,020 MW lignite-fired station at the Onakawana site. The third possibility for HVDC application is an asynchronous link with Hydro-Québec (see Appendix C). Ontario Hydro is studying such an application with an initial capacity of 1,000 MW, ultimately growing to 3,000 MW.

Figure. 7.1 Planned Nuclear Capacity as a Percentage of Firm Peak (Ontario Hydro East System)



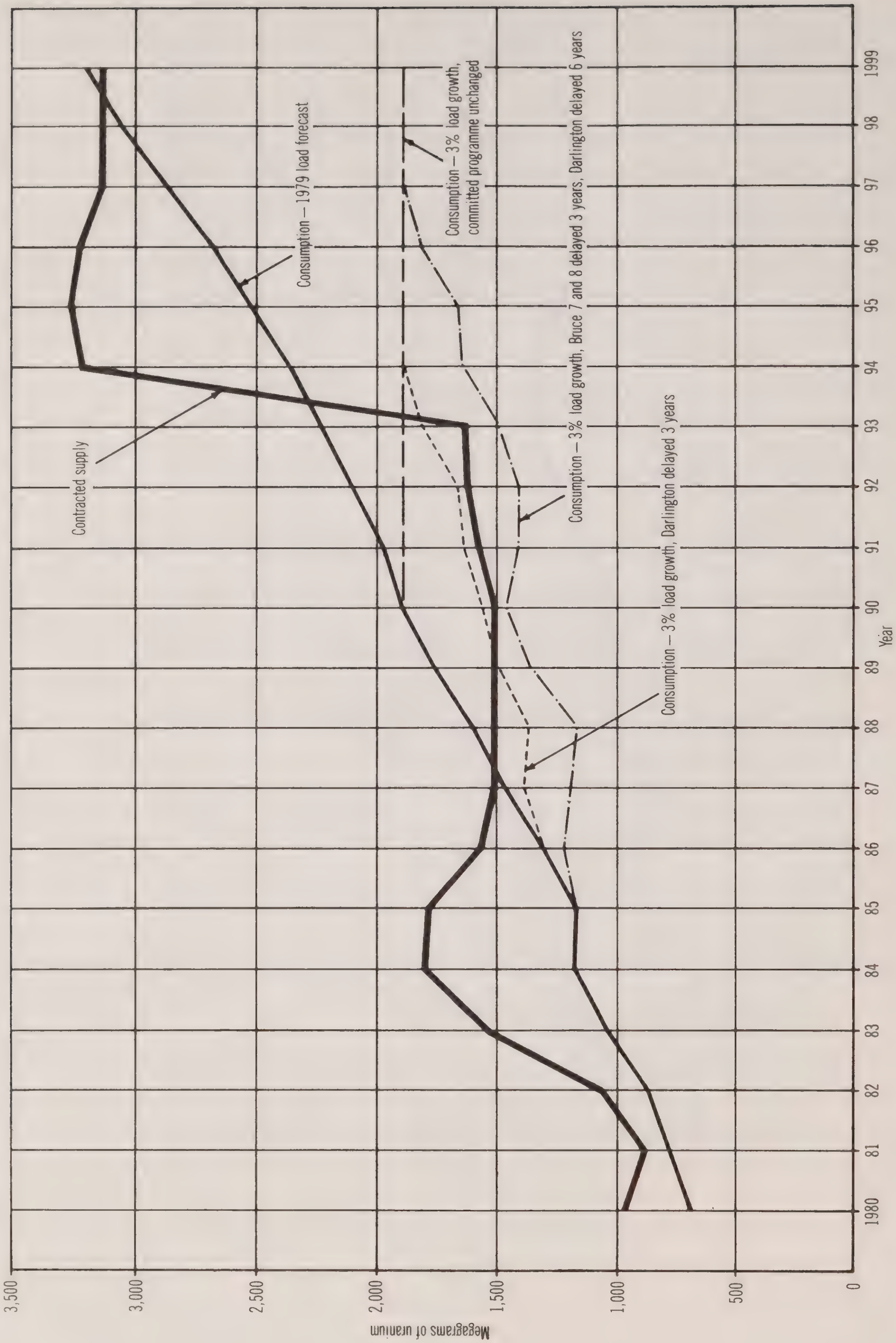
Source: RCEPP.

Figure. 7.2 Planned Generating Reserve Margin over Firm Peak (Ontario Hydro East System)



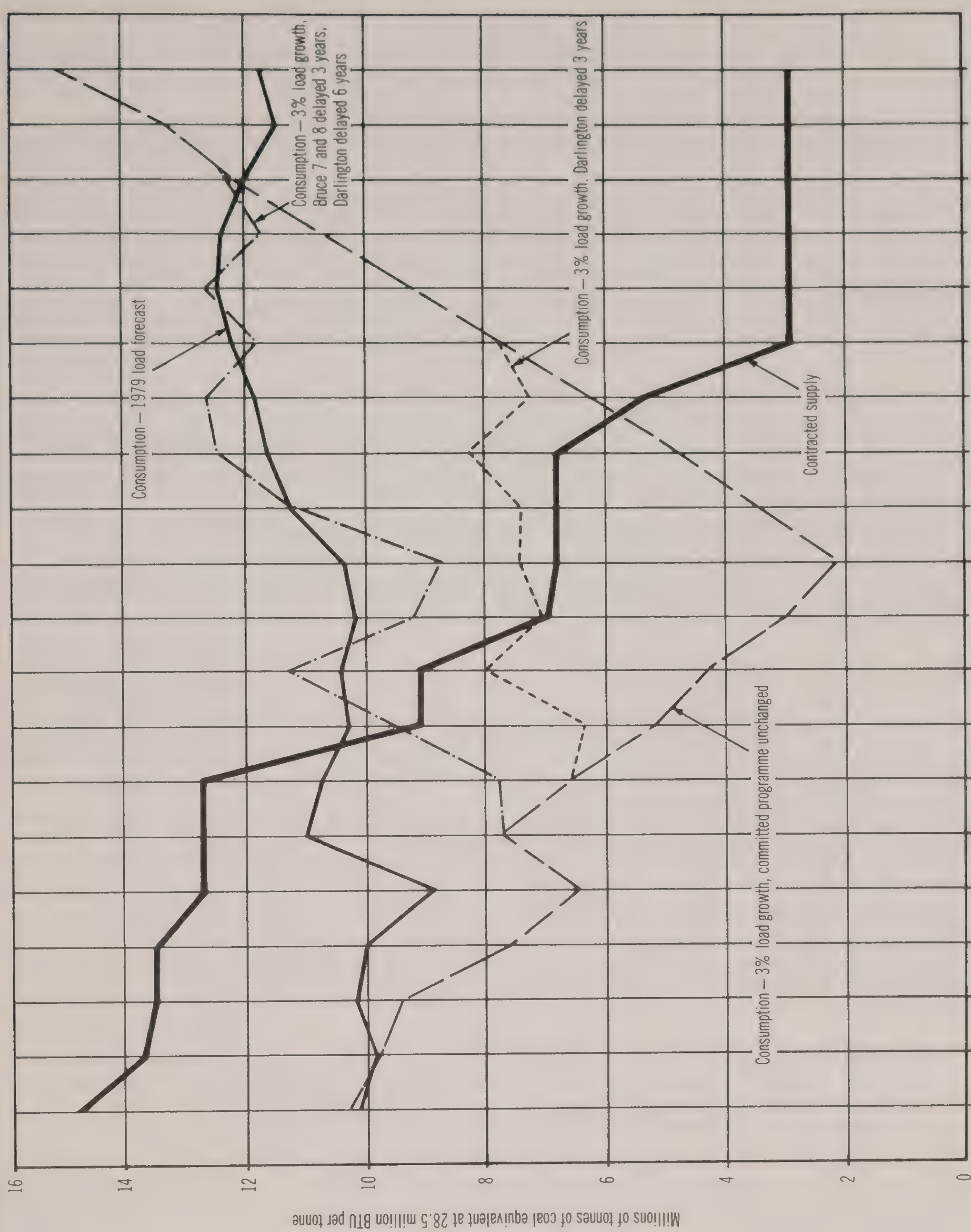
Source: RCEPP.

Figure 7.3 Uranium Supply and Demand (Ontario Hydro)



Sources: RCEPP and Ontario Hydro.

Figure. 7.4 Fossil Fuel Supply and Demand (Ontario Hydro)



Sources: RCEPP and Ontario Hydro

CHAPTER EIGHT

The Impact of Alternate Technologies

The planning of Ontario's electric power system will be influenced over the next two decades by the rise of some so-called unconventional energy technologies, as well as by an increased use of certain conventional technologies. This chapter deals with those new technologies that are likely to have the greatest direct affect on the bulk power supply system over the period 1981-2000. These technologies are load management, electric energy storage, co-generation, and generation from biomass and refuse-derived fuels. Strictly speaking, these technologies are neither new nor unconventional. In one form or another, they have been used in Ontario and elsewhere in the world for many years. What is significant about them is the recognition of their growing potential. The likely impact of these technologies will be described, with reference to system load patterns, the mix of conventional generating resources, and system reliability.

Other embryonic systems for electric power generation, such as solar photovoltaic, solar thermal, wind turbines, magnetohydrodynamics (MHD), geothermal, and fusion, are not expected to have any significant impact on Ontario's electric power system before the end of this century. Some remote power systems, such as wind-diesel and small-scale hydroelectric systems, may be suitable for isolated communities in northern Ontario that are not connected to an electric power system. Solar space heating and water heating are expected to make increasingly important contributions to Ontario's total energy needs, and the Ministry of Energy aims to have 1.5 per cent of total primary energy coming from this source by the year 2000.[1] Since solar heating does not directly affect the electric power system, it will not be discussed. Volume 4 of this Report provides a comprehensive description of both conventional and emergent energy technologies.

Load Management

"Load management" refers to combined efforts by an electricity utility and its customers to shift the consumption of electricity from traditional peak hours to periods of lower demand, in order to reduce the utility's overall peak demand and consequently increase the load factor. The benefits of load management are: a reduced need for new generating capacity; an increased utilization of the most efficient generating units and of transmission and distribution facilities; opportunities for lower customer rates; and increased business for manufacturers of electrical and electronic equipment through the sale of heat storage devices, time-of-day meters, and sophisticated electronic communications and control systems for controlling customer loads. Load management may be summed up, then, as the shaping of customer load profiles to achieve the most efficient utilization of a system's supply capacity. It does not necessarily imply the conservation of electric energy. Nor does it mean supply management by such measures as interconnections with other systems or energy storage by the utility, although these have the same objective.

The methods of load management may be broadly classified into three categories: pricing schemes and incentives; load control; and load reduction through voltage reduction, appeals to customers, load-shedding, and load-rationing. Pricing schemes such as time-of-use rates may play a significant role in the long run in shifting peak loads to off-peak hours. The marginal cost of supplying an additional kilowatt hour is, generally, higher during periods of high demand than during periods of low demand, because generating capacity is loaded according to merit order. Thus, with a pricing scheme based on this concept, there will be incentives to the customers to move some of their consumption from peak hours to off-peak hours. Time-of-use pricing schemes have received considerable attention among North American utilities over the last decade. One pioneer is the Long Island Lighting Company (LILCO), where time-of-use rates for commercial customers with a demand higher than 750 kW have been in effect since February 1977. LILCO is planning to extend the scheme to residential customers who consume more than 45,000 kW·h per year. Ontario Hydro is studying time-of-use pricing for its system and this study is being reviewed by the Ontario Energy Board.[2]

A form of load management that uses rate incentives has been practised in Ontario for many years in the interruptible service that is offered by Ontario Hydro to its large industrial users. This service, which is offered at reduced rates, may be interrupted during a system emergency or for reasons of economy. The total interruptible load in Ontario Hydro's system is about 750 MW.

"Load control" refers to direct control of customer loads by the utility, for example, the control of residential water-heaters. It has been used by many municipal utilities in Ontario to a limited extent. Load control, like interruptible service, can be exercised for economy as well as in an emergency. The control of residential water-heaters is an example of economic load control; decorative lighting and residential clothes-dryers are suitable applications for emergency load control. An indication of the potential for load control may be gained from the fact that about 10 per cent of the electricity used in 1974 in Ontario was consumed by residential and commercial hot-water heaters.[3]

The third approach to load management is used only in the event of an extreme emergency. The order in which the measures are imposed is voltage reduction, appeals to customer, load-shedding, and load-rationing. Voltage reduction and customer appeals were used by Ontario Hydro during the winter of 1976-7. Load-shedding is practised routinely in many developing countries. Load-rationing was used in the United Kingdom in 1976 and in California in 1974 and 1976.

Experience in Ontario indicates that there are essentially no negative customer impacts as a result of voltage reduction, provided that advance notice is given. It also indicates that a 5 per cent voltage reduction can lower the peak demand by about 2.7 per cent. This, then, appears to be an effective load-management technique to help maintain system reliability. Ontario Hydro has started to take account of this potential when calculating the reliability of its generation expansion programmes.[4] The experience during the winter of 1976-7 also proved that appeals to consumers at a time of dire emergency are effective – a 250 MW load reduction was effected by appealing to consumers through the mass media. Load reduction can also be achieved through appeals to industry, the results of which are easier to predict, primarily because of the close contacts between Ontario Hydro and its large industrial customers. This potential is estimated to be between 400 MW and 600 MW. The total potential load reduction through appeals to consumers amounts to about 5 per cent of the system demand. This potential can only be realized on a short-time emergency basis. Much less would be available on an extended or regular basis. An example of a load-shedding scheme is the one installed by Ontario Hydro in the Ottawa area to shed up to 300 MW, to avoid a voltage collapse, especially during the period of upgrading work on critical transmission circuits.[5] However, Ontario Hydro does not favour load-shedding or load-rationing as part of its normal system plan.

When considering load management, the distinction between the daily load factor and the annual load factor must be borne in mind (see Chapter 2). The annual load factor encompasses the weekly and seasonal as well as the daily variation in load. Load management is generally concerned with improving the daily load factors, although in doing so the annual load factor is also improved because the annual peak is thereby reduced. But load management does not aim at shifting loads from one season to another, because this is not possible at present and it may not be a desired option. Utilities such as Ontario Hydro take advantage of seasonal variations in the load by carrying out the necessary maintenance work on their generating equipment during the months of lower demand, thus avoiding the need for additional generating capacity for this purpose. If there is still an excess capacity in the months of lower demand, it can be utilized through some measure of supply management, such as a seasonal diversity exchange agreement with another system, whose annual peak occurs in a different season. Two systems that might benefit from such an agreement are Ontario Hydro, which is winter peaking, and the New York Power Pool, which is summer peaking.

The cost of implementing load management in Ontario is not precisely known. Investment in load-management hardware will have to be undertaken by all the parties involved – Ontario Hydro, municipal utilities, and the consumers. A study done for Ontario Hydro to provide a preliminary indication of the cost of load control in selected industries showed that in some industries only capital costs or only operating costs will be incurred, while in others both capital and operating costs will be incurred.[6]. The estimates range from zero to $830/kW reduced, in capital costs, and zero to $51/kW reduced, in annual operating costs. Hydro's estimates of the cost of load management to residential customers show that large water-heaters (with a capacity to store hot water for longer periods) will cost $100 to $150 more than the smaller, conventional units.[7]. The cost to the utility of various load-control systems (AM radio, telephone, distribution automation) is estimated to be between $250 and $450 per customer location for prototypes and less than $100 for mass-produced equipment. These estimates are very preliminary and Ontario Hydro expects to obtain more accurate estimates through field trials carried out in co-operation with various municipal utilities.

In the Ontario Hydro system, about 6,400 MW of capacity is hydraulic, more than half of which is suitable for peaking and intermediate loads. Since hydraulic generation has the lowest operating costs,

and since hydraulic units have excellent load-following capability, there is no incentive to manage the part of the peak load that is supplied by existing hydraulic generation. In such a case, the maximum theoretical potential for load management may be estimated by completely levelling off the load on thermal capacity. Ontario Hydro estimated this potential in its report on "The Role for Load Management in Ontario" to be about 3,700 MW in the year 2000, based on its 1978 load forecast and assuming no further development of hydraulic capacity or storage schemes.[8] The estimates are derived from the operation of thermal and hydraulic generating capacity on a December peak day in the East System. Ontario Hydro chose 50 per cent of the theoretical potential, that is 1,850 MW, as the 1978 target for load management by 2000, recognizing that major work to study the impact on the system of load management and other alternatives was still to be completed. The 50 per cent criterion also applies to the period 1985-99. This results in a target of 700 MW in 1987 and 1,400 MW in 1995.

There have been some developments since the publication of Hydro's load-management report. They may affect the load-management programme significantly and therefore deserve comment.

Ontario Hydro's 1979 load forecast is lower than its 1978 load forecast. Also, in recent years, there has been a shift in the winter peak from December to January, and the 1979 load forecast assumes that the January peak is about 3 per cent higher than the December peak. The Commission's estimates, based on the 1979 load forecast of January peak for the East System, indicate that the theoretical potential for load management could drop from 3,700 MW to 3,000 MW in the year 2000, assuming the same daily load factor. If the load grows only at an annual rate of, say, 3.5 per cent, this potential could be reduced to 2,200 MW.

Ontario Hydro is also developing a programme for the future expansion of peaking and intermediate-load hydraulic generation. In its "1979 Review of Generation Expansion Program", Hydro indicates that about 1,100 MW of this capacity is planned for the 1990s.[9] The cost of this development is estimated at $700/kW (1977 dollars). Since peaking hydraulic generation is an alternative to load management, the cost of installing such capacity must be weighed against the cost of load management to achieve the same objective. It is hoped that Hydro will acquire sufficient experience in load management in the 1980s to be able to assess the cost and potential for load management in the 1990s. This will create a better framework for making a decision on the peaking hydraulic potential. Development of 1,100 MW of this potential could decrease the maximum potential for load management by about 500 MW.

A third consideration is the development of energy storage (see the next section of this chapter). Studies by Ontario Hydro have indicated that underground pumped hydraulic storage can be an economic alternative, when compared with new coal-fired generation, for supplying the peaking requirements. The future development of pumped storage will be determined not only by the growth in load but also by the economic competitiveness of pumped storage compared with load management. It is not expected that pumped storage will be needed until the mid 1990s. By then, more experience will have been gained in load management, and this will facilitate the choice of an optimum mix between the two alternatives.

The long-term impact of load management on the generating mix is to reduce the need for peaking capacity and increase the share of high-capacity-factor generation such as nuclear and base-load hydraulic. For example, in the Ontario Hydro system, if the forecast growth in load is such that additional capacity will have to be added for peaking, intermediate-load, and base-load application, then load management will clearly reduce the need for peaking and intermediate load capacity. This is seen in Ontario Hydro's 1979 expansion plan, in which the ratio of base-load (nuclear) to peaking- and intermediate-load (coal and hydraulic) capacity additions in the 1990s is approximately 3:1, compared with an earlier ratio of 2:1 without load management (see Table 7.3 in Chapter 7).

However, in the short to intermediate term, load management may delay the need for base-load capacity. For example, if the load growth were lower, say 3.5 per cent per year, the existing and committed peaking and intermediate load resources would be sufficient to maintain an economic mix to the year 2000, and the additional requirements would be primarily for base-load capacity. Now, if the peaks could be reduced by load management, the utilization of the existing and committed fossil-fuelled resources could be increased, thus delaying the need for some base-load capacity. The higher fuel cost of fossil generation may, however, offset much of the capital cost savings.

Load management reduces peaks, but, if the system capacity is reduced in proportion, a reduction in system reliability must be expected. The reason for this is that, as the daily load factor increases, the daily load curve flattens, and there will be a greater exposure of system load to equipment outages. This

is not to suggest that some reduction in capacity is not possible but to point out that the percentage reserve margin (with respect to the managed peak) will have to be increased if the same level of reliability is to be maintained. On the other hand, load management, and especially load control, reduces the uncertainty with respect to the daily load profile, and this may benefit the system planner by reducing the risk of having too much or too little generating capacity.

Ontario Hydro's load management initiatives are worthy of support. Hydro is relatively inexperienced in load management and its participation with the municipal utilities over the next few years will provide valuable experience in assessing more accurately the cost and public acceptance of load management. To determine the long-term potential of load management, other alternatives such as peaking and pumped hydraulic resources must be considered. Load management also offers some challenging opportunities for the province's electronics industry to design one-way and two-way communication systems for the monitoring and control of loads at the customers' premises.

Electric Energy Storage

Due to the nature of the daily demand for electricity it may be desirable to store the surplus output of low-cost base-load stations during the hours of low demand and use the stored energy during the hours of high demand. The economic attractiveness of a storage scheme depends upon its capital cost, reliability, storage capacity, and operating efficiency, on the availability of low-cost surplus energy, and on the cost of alternative ways of supplying the daily peaks. A storage system may also increase the operating flexibility of the total generating system by reducing the need for load-following by large base-load units such as nuclear units.

No practical utility-scale techniques are available at present for the storage and recovery of electric energy directly. However, the storage of electricity in the form of the potential energy of water has been practised for several years. This is generally known as hydraulic pumped storage. By means of reversible motor-generator and pump-turbine units, water is pumped up from a lower reservoir to a higher reservoir during low-demand periods and this water is then used to generate electricity when needed. Ontario Hydro has one such plant at the Sir Adam Beck Generating Station at Niagara Falls, with a peak capability of about 100 MW. Although most hydraulic pumped storage systems around the world are located above the ground, underground pumped storage holds considerable potential. In such a scheme, the lower reservoir is excavated below the ground level, and a large nearby body of water serves as the upper reservoir. The pumping-generating station is located underground, and only the control building, transformers, and switchyards are visible on the surface. Thus, from an environmental point of view, underground pumped storage is preferable to an above-ground scheme.

Several storage schemes have been studied by Ontario Hydro. Significant among the above-ground pumped storage sites studied since 1965 are Delphi Point (2,000 MW) and Matabitchuan (400 MW). A preliminary study was carried out in 1974 to evaluate other storage schemes and identify those deserving further study for development in this century.[10] A major thrust for these studies was the need to reduce load-following by CANDU nuclear units that had been planned at that time for the 1980s and the 1990s. The 1974 study indicated that potential candidates for more detailed investigation were both above-ground and underground hydraulic pumped storage, compressed-air storage, feedwater storage, steam storage, and battery storage (see Volume 4 of this Report for a detailed description of various storage schemes).

In order to assess the technical and environmental feasibility of the underground pumped storage concept and its cost, Ontario Hydro authorized Acres Consulting Services Limited to undertake a study whose results were published in January 1976.[11] The report concluded that "underground pumped storage, utilizing Lake Ontario as an upper reservoir, is a technically feasible means of providing energy storage for the Ontario Hydro system" and that "environmental considerations associated with construction activities will play an important part in the siting of the plant" at any location along the north shore of Lake Ontario.[12] The report further suggested that the "economic feasibility of underground pumped storage must be determined by evaluating the concept within the Ontario Hydro system using the parameters and costs set out in this study."[13]

Ontario Hydro has, since late 1978, been examining the applicability to its system of the potential storage schemes mentioned earlier.[14] From these studies, it appears that underground pumped storage is the most economic of the various storage alternatives for consideration in this century and that the Hydro system could accept about 2,000 MW of pumped storage by the late 1990s on the basis of the 1979

load forecast. The ranking of other storage schemes from the most economic to the least economic is as follows: above-ground pumped storage (Delphi Point and Matabitchuan), compressed-air storage, nuclear feedwater storage, lead-acid battery storage, and nuclear-steam storage.

Concerning the role of pumped storage as a peaking plant, Ontario Hydro's studies indicate that pumped storage would be economically more attractive than new coal-fired capacity, even if no surplus nuclear energy was available for pumping, that is, if pumping was done by power supplied by coal-fired units. However, the degree to which pumped storage could replace new coal-fired capacity will depend on the required annual capacity factor. Any new coal-fired capacity is most likely to be operated to supply the intermediate load, that is, annual capacity factors of 10-55 per cent. The maximum annual capacity factor of which the pumped storage schemes are capable, assuming a daily generating period of eight hours, is approximately 33 per cent. This, coupled with the existence of considerable amounts of fossil-fuelled capacity and an upper limit on the availability of surplus nuclear generation, puts an upper limit on the acceptability of pumped storage in the bulk power system. It should also be borne in mind when comparing pumped storage with other generation alternatives that it is not a net producer of energy and thus does not increase the reliability of the system's energy supply. In fact, pumped storage increases the system's primary energy requirements because of the ineffіcency of the pumping-generating cycle, which is approximately 70 per cent.

This disadvantage of pumped storage is offset to some extent by the fact that hydraulic units have much lower forced outage rates than fossil-fuelled units, which suggests that, during peak periods, pumped storage units have a higher load-carrying capability.

In the light of the preceding discussion, Ontario Hydro's conclusion that "for early inclusion in Ontario Hydro's generation program, the most economic large-scale energy storage alternative is pumped storage, either above-ground or underground, and . . . no more than a watching brief should be kept on alternative storage technologies" appears valid.[15] However, the potential for use of storage schemes in the system is uncertain, to the end of the century. The single most important factor will be the growth in demand. If the forecast growth rate falls below 4 per cent per annum, Ontario Hydro's estimated potential of 2,000 MW will be reduced substantially, and, if the load grows at only 3 per cent per annum, there may not be any need for storage until the next century. This is particularly relevant in the light of Hydro's plans to make greater use of the province's remaining potential for peaking- and intermediate-load hydraulic generation (see Chapter 7). The economic justification for storage will also be influenced by the cost and success of Hydro's load-management programme, which has the same objective as storage.

Co-Generation

Co-generation refers to the utilization of the steam as well as the electricity at a thermal generating site. It is of potential importance where there is a demand for both steam and electricity, for example, for industrial processes, and for universities, hospitals, and commercial buildings. Steam can be used as process-steam or for space heating and water heating. The significance of co-generation as a supply option for the future arises because of the increased efficiency of fuel utilization that it implies. In a conventional thermal electricity generating plant, about 9,000 BTU are required to generate 1 kW·h of electricity, which corresponds to an efficiency of 38 per cent. The remaining 62 per cent of the heat energy in the steam is discarded as waste. But when this steam can be utilized in a co-generation scheme, the efficiency of electricity generation may rise to 80 per cent. (It is important to note that the electricity output is limited by the utilization of steam in a co-generation scheme; that is, if electricity output has to be increased at the same efficiency, the steam utilization must be increased proportionately.)

Many studies have been carried out in the past on the economic and technical potential of co-generation in Ontario. The most promising of the various co-generation alternatives, for this century, appears to be industrial co-generation. Prompted by the potential for energy conservation in the industrial sector, Ontario Hydro and the Ontario Ministry of Energy in December 1978 co-sponsored a seminar on industrial co-generation.[16] The seminar provided an opportunity for the representatives of Ontario Hydro, industry, and government agencies to exchange information and discuss the economic, technical, and institutional barriers to the implementation of co-generation.

As far as the capital costs of co-generation equipment are concerned, it is evident from various studies that, while these costs vary widely from plant to plant, they drop steeply with an increase in the scale of

installation, up to about 15 MW. In bigger installations, the economies of scale are not as pronounced, and the capital costs are in the \$300-\$400/kW range for oil- and gas-fired co-generators.[17] For coal- and low-grade-refuse-fuel-burning equipment, the capital costs are expected to be higher. The operations and maintenance costs are \$10-\$20/kW per year. Typical prices paid by industry for No. 2 oil, residual oil, and natural gas in 1977 were \$2.23, \$1.60, and \$1.75 per million BTU, respectively. The fuel costs for co-generation in Ontario varied between \$24/kW per year and \$80/kW per year in 1977 with an 80 per cent load factor. The weighted average cost was about \$56/kW per year.[18]

The economic potential of co-generation is analysed in detail in Volume 5 of this Report. It is shown there that the economics of co-generation are strongly influenced by the financing environment. Private industries expect a quick return on co-generation, since it has a lower priority than investments that contribute directly to the increasing of output. As a result, the discount rates acceptable to the private sector tend to be significantly higher than those used in the public sector, for example, by Ontario Hydro. Other factors affecting the economic potential of co-generation are the cost of power purchased from Hydro and the relative future costs of alternative fuels.

The economic analysis described in Volume 5 of this Report indicates that the additional potential for co-generation in Ontario in both the industrial and the non-industrial sectors to the year 2000 would be between 400 MW and 2,300 MW, depending on the assumptions about the discount rate, the price of boiler fuel, and the price of electricity. The analysis found that, while gas-fired co-generation will be preferred by the business sector in the 1980s because of its lower capital costs, "with financing and coal purchasing conditions equivalent to Ontario Hydro's, coal-fired co-generation remains cost-effective relative to nuclear power for some time to come".[19]

In order to overcome the economic constraints, close co-operation between industry, government, and Ontario Hydro is necessary. The importance of such co-operation is demonstrated by studies done for the U.S. Department of Energy which estimated the co-generation potential in the U.S. to be 6,000 MW without government action and 16,000 MW with government incentives.[20]

In Ontario today, there is approximately 510 MW of installed capacity in the form of industrial co-generation, 93 per cent of which is concentrated in plants with a capacity of more than 5 MW. Ontario's co-generation capacity represents about 2.5 per cent of the total capacity within the province. In contrast to this is the situation in West Germany, where about 30 per cent of total electric generation capacity is installed in industrial plants. The total theoretical present potential in Ontario for industrial co-generation (based on estimates of steam demand) is in the order of 1,200 MW to 1,400 MW. The technical constraints acting against utilization of this potential appear to be the specific requirements for steam and electricity of individual plants. Industrial plants that are technically most suitable for co-generation are those with a high load factor for both steam and electricity demand.

There are several advantages for the industrial co-generation customer in parallel operation with the utility. Significant among these are stable frequency and voltage, increased reliability of supply, more efficient utilization of co-generation capacity in the face of the customer's changing need for steam and electric power, and opportunities for the sale of excess power to the utility. Advantages to the utility include the purchase of economy power as well as emergency power from the customer. Disadvantages to both the customer and the utility arise from increased short-circuit currents; increased risk of damage to the customer's generators through faulty synchronization; the cost of additional equipment for protection relays, synchronizing facilities, and higher short-circuit currents; and an overall increase in the complexity of the operation.

An infusion into the Ontario Hydro system of many small co-generators would undoubtedly make generation dispatch and fuel allocation more complex. But this must be weighed against the overall benefits, mentioned earlier, for both the utility and the industrial customers, of diversification, decentralization, and reductions in system reserve capacity. These reductions are considerable when an additional industrial load is supplied by small co-generators rather than by Ontario Hydro's large centralized stations. Figure 4.2 of Chapter 4 showed how the reserve margin varies with the size of a generating unit. (Throughout this discussion, it has been assumed that exchanges of power between the utility and the industrial plants is possible in emergencies and for reasons of economy. This kind of an arrangement is synonymous with interconnections among utilities.) As far as an increase in reliability and an overall reduction in reserve requirements are concerned, the industrial customers have a lot more to gain than Ontario Hydro has. However, Hydro's attitude towards parallel operation with industrial co-generators is positive despite operational complexities:

> Some operating, protective relaying and possible short-circuit in-feed problems will result from operation of customers' on-site generation in parallel with Ontario Hydro's system. These problems have been resolved in the past by co-operation among the customer's technical and operating staff, his consultant and Ontario Hydro. Hydro will continue this co-operation to help encourage conservation of finite energy resources and other benefits to the customer which result from parallel operation of his on-site generation with the electrical supply system.[21]

While the economic potential for industrial co-generation depends on the capital cost, the cost of fuel, and the financing environment, it is the demand for steam that will determine the maximum potential. The demand for steam in the manufacturing sector grew by 2.8 per cent per year between 1964 and 1975, a period of high economic growth. Because of the increasing role of conservation in the manufacturing industries, and slower industrial growth, the growth in the demand for steam up to the end of the century is likely to be more like 2 per cent per annum. This growth rate, when applied to the existing total potential of 1,200 MW to 1,400 MW, gives a total of about 2,000 MW by the year 2000. With about 500 MW of co-generation already existing, that means an additional potential of about 1,500 MW. This does not include the co-generation potential at some non-industrial installations, such as universities, hospitals, and commercial firms that operate steam plants to provide heating during the winter months, or the self-generation of electricity by firms that have no process-steam requirements and where one would expect to find utility-type condensing turbines. Ontario Hydro has estimated the self-generation potential to be about 1,450 MW in 1977.[22]

Because of its high annual load factor, co-generation will tend to replace Ontario Hydro's base-load capacity requirements, that is, CANDU nuclear stations. This could cause Hydro's load factor to deteriorate, with an increase in the unit cost of electricity to Ontario Hydro. However, Hydro's position is that "these negative effects on Hydro as the result of industrial co-generation should be viewed as only short term. Improved load-management practices, and general load growth in the long term, offset utility cost increases caused by the loss of some industrial customers. Furthermore, significant levels of industry-owned generation plants could reduce Ontario Hydro's capital requirements, and . . . the need for new central generating capacity."[23]

Biomass and Refuse-Derived Fuels

Biomass includes forest industry (timber, pulp and paper, etc.) wastes, uncommercial standing timber, and specially planted fast-growing wood species such as hybrid poplar. Refuse-derived fuels (RDF) are fuels obtained by processing municipal solid waste. Both biomass and RDF can be used as boiler fuel to generate electricity.

The wood-product industry in Ontario has been using wood-waste for many years in a co-generation mode to supply process-steam as well as electricity. The incentive to use wood-waste in this industry has been twofold: to reduce fuel costs and to solve a waste-disposal problem. As the prices of energy from conventional sources increase, the energy potential of wood-waste could help the lumber and pulp and paper industries to become increasingly energy self-sufficient and to improve their competitive positions. The potential to become self-sufficient is much greater in pulp mills than in newsprint mills, which are large consumers of electricity.

A study of the burning of wood-waste for steam and electricity production in the Township of Hearst in northwestern Ontario has attracted considerable attention recently.[24] It was motivated originally by problems arising in the disposal of wood-waste from the lumber mills in the Hearst area. Following a conceptual study in 1976 by SNC Consultants, Acres Shawinigan were commissioned in 1977 by the Ontario Ministry of the Environment to prepare a preliminary design and carry out an economic evaluation of a wood-waste-fired steam and power plant at Hearst. Both Ontario Hydro and the Ministry of Energy participated actively in the study, which showed that the 117,000 tonnes of oven-dried wood per year could supply fuel for a plant to generate 14 MW of electricity at peak and an average of 36,000 kg/hour of steam, at a total capital cost of $22.6 million (1978 dollars). According to the Ministry of Energy, the economics of this co-generation facility are marginal under present conditions. Shell Canada is investigating an alternative project that would use the waste to produce wood pellets as a substitute for fossil fuels in industrial co-generators.

The hybrid poplar, developed by the Ministry of Natural Resources, has a maturing period of about 10 years compared with 30 years for existing hardwood forests. The primary aim of the fast-growing hybrid poplar programme is to replenish Ontario's forest resources, but the idea of cultivating these trees for fuel also holds considerable promise. A preliminary study was undertaken for the Commission

by Morris Wayman Limited in 1978, to examine the potential of plantation wood for the generation of electricity in Ontario.[25] The study concluded that plantations of hybrid poplar in eastern Ontario could fuel about 1,600 MW of generating capacity at a cost competitive with fossil-fuelled generation. Other advantages cited for wood-fired generation were job creation within the province and increased reliance on an indigenous and renewable resource.

Ontario Hydro undertook its own evaluation of the economics of wood-fired stations and released the results in a report in August 1979.[26] The study's basic conclusion was that wood-fired generation is not economically competitive with nuclear or coal-fired generation for operation at any capacity factor. An analysis of Hydro's cost estimates indicates that the capital and fixed operations, maintenance, and administration (OM&A) costs of wood-fired generation are about twice those of coal-fired generation and about 40 per cent higher than CANDU nuclear generation. The OM&A costs of wood-fired generation are a very high percentage of its capital costs – from about 40 per cent for a 3 × 150 MW station to as much as 120 per cent for a 24 MW single-unit station. The corresponding value for Hydro's large coal-fired stations is in the 25-30 per cent range. The limitations on the size of the wood-fired stations, because of the nature of the fuel, tend to make them economically less attractive. Unless attempts are made to reduce the capital and OM&A costs of wood-fired generation or to increase plantation yields significantly, the rationale for developing the wood potential for electricity generation has to be other than economic. Even if such attempts are successful, the likely role of central wood-fired generation appears to be for intermediate-load applications. The economics of wood-fired generation may be improved if this method is used in a specific local application in a co-generation mode. The other technical characteristics of wood-fired generation, such as reliability, load-following capability and part-load operation, appear to be similar to those of the fossil-fuelled units.

Ontario produces about 5.5 million tonnes of municipal refuse every year with an average heat content of 5,000 BTU/lb. (11.65 MJ/kg). If all of this potential were used as fuel to generate electricity, it would produce approximately 6,000 GW·h of electricity annually, the output of a 1,000 MW station at an annual capacity factor (ACF) of 70 per cent. However, it is unrealistic to assume that all the refuse can be collected and all the combustible product can be recovered in preparing the fuel. A realistic estimate of the recoverable heat potential is 60 per cent,[27] which puts the maximum potential for RDF at 3,600 GW·h per year, or 600 MW at 70 per cent ACF. This corresponds to about 3.5 per cent of the demand for electricity in Ontario in 1978.

It appears that a significant proportion of the RDF potential will be utilized in a co-generation mode to generate electricity and provide district heating in urban centres, rather than to generate electricity alone. This is evident from the apparent lack of success of the "watts from waste" programme involving the Ministry of the Environment, Metropolitan Toronto, and Ontario Hydro. The programme was designed to demonstrate the feasibility of burning about 180,000 tonnes of RDF per year, mixed with coal, in one of the units at Ontario Hydro's Lakeview generating station. The ratio of the heat content of coal to the heat content of RDF was expected to be about 7 to 1. However, for a variety of reasons, the project has been suspended. A major factor was the cost of equipment for the RDF separation and processing plant. Tenders to provide the equipment indicated that the costs would be almost twice those expected. Final estimates of the cost of the processing plant and the facilities at the Lakeview G.S. were in the order of $46 million.

Other alternatives were being considered to utilize Toronto's refuse, including a scheme to burn refuse directly in incinerators for district heating, or modifying the boilers at Ontario Hydro's Hearn G.S. (currently mothballed) to burn a lower-quality RDF to generate electricity as well as steam for district heating. As a result, the Ministry of the Environment and Metropolitan Toronto are undertaking a master-plan study using computerized models to evaluate the best alternative for using the energy potential of Toronto refuse. The results of the study, whose cost will be shared equally by the two participants, are expected to be available by the early spring of 1980. Another study is under way, in the Regional Municipality of Peel, on the burning of refuse to generate electricity and provide process-steam for a Domtar Limited plant in Mississauga.

The use of RDF for direct generation of electricity or in a co-generation mode would help to solve the problem of municipal waste disposal and provide some diversity in fuel base by incorporating an indigenous, renewable, and cheap source of energy. Economic considerations alone should not dictate decisions on RDF-fuelled plants. The capital cost of the refuse-processing plants might be high, but this must be weighed against the cost of alternate methods of waste disposal, their effects on the environment, and the savings associated with replaced fuel and the security of its supply.

A lead in RDF-based electricity generation has been taken by the City of Milwaukee, Wisconsin, where 230,000 tonnes of city refuse is processed every year to fuel the boilers of Wisconsin Electric Power Company. The electricity so generated from the RDF would supply full service to 30,000 homes.

Summary and Conclusions

The emergent technologies that are expected to have the greatest direct impact on the electric power system of Ontario are load management, electric energy storage, co-generation, and generation from biomass and refuse-derived fuels. Some forms of load management are already being practised by Ontario Hydro, for example, the interruptible service to industrial customers. Ontario Hydro is undertaking a comprehensive load-management programme to reduce primary peak loads in the 1980s and 1990s. We support Ontario Hydro load-management initiatives. Until the late 1980s, load management may appear to be unjustifiable, because of the surplus of generating capacity faced by Ontario Hydro. However, the cost of implementing load management is not known with any degree of certainty, and Ontario Hydro's participation in it with the municipal utilities over the next few years will provide the needed opportunity to assess its cost and its acceptance by the public. This will facilitate decisions that will eventually have to be made concerning load management in comparison with other alternatives such as peaking hydroelectric resources and storage schemes. Through the associated hardware requirements, load management could also stimulate the province's electronics industry.

Storage schemes serve the same objective as load management. Studies conducted by Ontario Hydro have identified underground pumped storage as an alternative for large-scale storage of electric energy that would be viable and economic before the end of the century. The economic justification for storage will depend on the need for peaking capacity and the availability of surplus nuclear energy during off-peak hours. Under Ontario Hydro's 1979 load and generation plan, the system could accept up to 2,000 MW of storage by the late 1990s, but if the load were to grow only at 3 per cent per annum, there might not be an economic justification for storage.

In Ontario today, there is approximately 510 MW of electrical co-generation capacity in the industrial sector. The growth of co-generation in the industrial and non-industrial sectors will be influenced strongly by the nature of the financing, the price of boiler fuels, and the price of electricity purchased from Ontario Hydro. On the basis of an estimated 2 per cent annual growth in steam demand, the additional potential for industrial co-generation by 2000 is about 1,500 MW. This does not include the co-generation potential of some non-industrial installations. An economic analysis discussed in Volume 5 of this Report indicates that the total additional potential for co-generation to the year 2000 could be between 400 MW and 2,300 MW depending on the assumptions concerning discount rates and the prices of fuels and purchased electricity. Any growth in co-generation will tend to replace Hydro's base-load requirements. Parallel operation of many co-generators with Ontario Hydro's system will increase the overall complexity of system operation. However, in view of Hydro's positive attitude towards parallel operation and the advantages of diversification, decentralization, and reduction in system reserve capacity, co-generation should be encouraged.

The economics of wood-fired generation indicate that it cannot at present compete with coal-fired and CANDU nuclear generation. The economics may improve if wood is used in particular local applications in a co-generation mode. The municipal refuse in Ontario could generate about 3.5 per cent of Ontario's electricity demand, but a substantial part of it is likely to be used for district heating. In this respect, it is noted that a master-plan study undertaken jointly by the Ontario Ministry of the Environment and Metropolitan Toronto to evaluate the best way of using Toronto refuse is expected to be completed by the spring of 1980. Utilizing the energy potential of refuse is an excellent way to solve the waste-disposal problem. Also, it would incorporate in the system a cheap source of energy and one that is both indigenous and renewable, and would therefore enhance the diversity and security of the fuel base.

APPENDIX A

Ontario Hydro's Generating Resources

This appendix contains a list of Ontario Hydro's power generating resources, station-by-station for both the East System and the West System. For each generating station, the number of units, the first in-service dates, and the generating capacity are listed. For each of the two systems, a historical record is given, starting in 1935, for the primary peak and energy demands and the peak generating capacity. The source of this information is Ontario Hydro's Power Resources Report No. 790201.

Definitions

Authorized Resources

These are resources that have been authorized by Ontario Hydro for design and construction. Long-range projected resources that have not been authorized are not included.

Hydraulic Resources

Peak Resources (MW)

This refers to the peak rating of a hydraulic generating station, which is the maximum net power available to supply system load for at least five days a week, for daily uninterrupted periods equal to:

1. Two hours for the East System excluding the Sir Adam Beck generating stations.
2. Twenty minutes for the Sir Adam Beck generating stations.
3. Eight hours for all West System generating stations.

Hydraulic peak and energy resources are based on monthly mean river flows. They are shown for two alternative values:

1. "Dependable" values, attainable or exceeded 98 per cent of the time.
2. "Median" values, attainable or exceeded 50 per cent of the time.

Thermal Resources (fossil and nuclear)

Peak Resources (MW)

This refers to the peak rating of a thermal unit or generating station, which is the maximum net power available to supply system load for a minimum of two hours a day, without exceeding specified limits of equipment stress.

Maximum Continuous Rating (MW)

This is the expected net maximum electricity output of a unit or generating station operating continuously under the designed inlet steam conditions.

Thermal Resources (combustion turbines)

Peak Resources (MW)

The peak and energy outputs of the combustion turbines vary considerably with changes in ambient air temperature. The peak resources are based on the average of recorded daily maximum temperatures for December, January, and February.

Table A.1 Ontario Primary Demands and Total Resources – East System

Year	Ontario primary demand				December dependable peak resources					
		Annual energy								
	December peak(MW)	GWh	Average MW	Annual load factor(%)[a]	Hydraulic (MW)	Fossil steam (MW)	Nuclear (MW)	Purchases (MW)	Combustion turbine (MW)	Total dependable (MW)
1935	854.8	4,327.0	493.9	57.8	744.2	0	0	369.9	0	1,114.1
1936	927.2	4,718.7	537.2	57.9	929.1	0	0	159.3	0	1,088.4
1937	998.5	5,314.7	606.7	60.8	1,044.2	0	0	283.3	0	1,287.5
1938	1,054.3	5,303.3	605.4	57.4	1,025.9	0	0	396.5	0	1,422.7
1939	1,199.0	5,861.2	669.1	55.8	1,017.3	0	0	451.6	0	1,468.9
1940	1,266.0	7,046.8	802.2	63.4	995.2	0	0	496.5	0	1,491.7
1941	1,451.8	8,135.1	928.7	64.0	998.6	0	0	587.5	0	1,586.1
1942	1,470.1	9,054.2	1,033.6	70.3	1,030.3	0	0	648.2	0	1,678.5
1943	1,530.6	9,207.3	1,051.1	68.7	1,093.9	0	0	659.1	0	1,753.0
1944	1,612.4	9,199.3	1,047.3	65.0	1,082.8	0	0	652.2	0	1,735.1
1945	1,667.4	9,646.4	1,101.2	66.0	1,143.5	0	0	691.0	0	1,834.5
1946	1,922.0	9,791.4	1,117.7	58.2	1,173.3	0	0	708.2	0	1,881.5
1947	2,134.9	11,639.9	1,328.8	62.2	1,243.7	0	0	720.3	0	1,964.0
1948	2,245.2	12,027.9	1,369.3	61.0	1,318.9	0	0	717.7	0	2,036.6
1949	2,258.0	12,326.7	1,407.2	62.3	1,358.5	0	0	746.0	2.0	2,106.5
1950	2,554.0	13,876.7	1,584.1	62.0	1,680.1	53.0	0	7464.1	0.5	2,497.7
1951	2,850.1	15,825.8	1,806.6	63.4	1,801.3	202.0	0	703.1	0.3	2,706.7
1952	3,019.3	16,910.4	1,925.1	63.8	1,960.8	444.0	0	687.1	0.3	3,092.2
1953	3,202.8	18,018.4	2,056.9	64.2	1,968.9	652.0	0	681.1	0.5	3,302.5
1954	3,389.1	18,815.6	2,147.9	63.4	2,710.9	450.0	0	681.1	0.5	3,842.5
1955	3,854.6	20,865.8	2,381.9	61.8	2,893.8	636.0	0	682.3	1.0	4,213.1
1956	4,111.8	22,870.2	2,603.6	63.3	2,922.8	616.0	0	641.2	1.3	4,181.3
1957	4,330.7	24,465.8	2,792.9	64.5	3,264.8	616.0	0	592.2	1.8	4,474.8
1958	4,644.3	25,265.6	2,844.2	62.1	4,019.8	616.0	0	593.2	1.8	5,230.8
1959	5,082.7	28,382.4	3,240.0	63.7	4,322.1	616.0	0	619.2	1.8	5,559.1
1960	5,278.4	29,561.0	3,365.3	63.8	4,317.2	994.0	0	617.2	1.9	5,930.3
1961	5,480.5	30,879.2	3,525.0	64.3	4,146.2	1,372.0	0	617.5	1.6	6,137.3
1962	5,811.3	32,736.8	3,737.1	64.3	4,135.6	1,740.0	0	617.5	1.0	6,494.1
1963	6,305.1	34,517.3	3,940.3	62.5	4,437.3	2,014.0	0	617.5	1.0	7,069.8
1964	6,699.0	37,317.6	4,248.4	63.4	4,445.3	2,026.0	0	617.0	1.0	7,089.3
1965	7,344.3	40,399.4	4,611.8	62.8	4,391.4	2,526.0	0	521.3	74.0	7,512.7
1966	8,028.1	44,460.9	5,075.4	63.2	4,526.4	2,588.0	0	521.5	149.0	7,784.9
1967	8,401.1	47,560.4	5,429.3	64.6	4,611.0	2,888.0	0	522.5	288.0	8,309.5
1968	9,387.5	51,771.6	5,893.9	62.8	4,931.0	3,653.0	200.0	523.6	321.0	9,628.6
1969	9,924.5	55,080.6	6,287.7	63.4	5,173.0	4,307.0	208.0	523.3	321.0	10,532.8
1970	10,638.5	59,689.4	6,813.9	64.0	5,387.0	5,853.0	194.0	191.4	336.0	11,961.9
1971	10,870.4	63,396.5	7,237.0	66.6	5,879.0	5,814.0	1,204.0	193.0	343.5	13,233.5
1972	12,004.8	68,486.2	7,796.7	64.9	5,538.0	5,804.0	1,770.0	193.6	358.5	13,664.1
1973	12,858.1	73,047.3	8,338.7	64.9	5,715.0	7,334.0	2,284.0	993.9	366.0	16,692.9
1974	12,903.6	77,388.2	8,834.3	68.5	5,715.0	7,754.0	2,284.0	1,194.8	376.6	17,324.4
1975	13,974.1	79,511.5	9,076.7	65.0	5,577.0	8,321.0	2,284.0	1,195.8	384.4	17,762.2
1976	15,079.3	85,564.8	9,741.0	64.6	5,599.2	9,478.0	2,284.0	1,007.6	403.0	18,771.8
1977	14,853.9	86,964.8	9,927.5	65.5	5,709.8	10,614.0	3,764.3	9.1	445.0	20,542.2
1978	14,940.2	89,614.3	10,230.0	66.3	5,822.2	11,211.0	4,504.3	8.2	445.0	21,990.7

Note a) The annual load factor is calculated on the basis of the annual peak, which is not necessarily identical to the December peak.

Table A.2 Summary of Hydraulic Resources Installed and Authorized – East System

Generating station	Number of units	First power dates	December peak resources Median (kW)	December peak resources Dependable (kW)
NIAGARA RIVER				
Sir Adam Beck No. 1	10	1922-30		
Sir Adam Beck No. 2	16	1954-8		
Pumping generating station	6	1957-8		
Total			1,880,000	1,880,000
Ontario Power	15	1905-13		
	3	O/S 1967		
Total			105,000	28,000
Toronto Power	11	1906-15	Station removed from service February 12, 1974.	
	6	O/S 1969		
	5	O/S 1974		
DeCew Falls No. 1	9	1904-11		
	3	O/S 1967		
DeCew Falls No. 2	2	1943-7		
Total			155,000	155,000
ST. LAWRENCE RIVER				
Robert H. Saunders	16	1958-9	776,000	702,000
OTTAWA RIVER				
Otto Holden	8	1952-3	247,000	225,000
Des Joachims	8	1950-51	420,000	418,000
Chenaux	8	1950-51	116,000	110,000
Chats Falls (Ontario half)	4	1931	96,000	84,000
MADAWASKA RIVER				
Mountain Chute	2	1967	167,000	165,000
Barrett Chute	2	1942	42,000	42,000
Barrett Chute Extension	2	1968	130,000	130,000
Stewartville	3	1948	64,000	64,000
Stewartville Extension	2	1969	103,000	102,000
Arnprior	2	1976-7	78,000	78,000
Calabogie	2	1917	4,000	3,000
TRENT RIVER				
Heeley Falls	3	1913-19	11,400	11,400
Ranney Falls	3	1922-6	8,600	8,600
Meyersburg	3	1924	5,200	5,200
Sidney	4	1911	3,400	3,100
Hagues Reach	3	1925	3,400	3,400
Seymour	5	1909-11	3,100	3,100
Frankford	4	1913	2,600	2,600
Sills Island	2	1926	1,600	1,600
OTONABEE RIVER				
Auburn	3	1911-12	1,800	1,800
Lakefield	1	1928	1,700	1,700
MISSISSIPPI RIVER				
High Falls	3	1920	2,600	2,600
Galetta	2	1907	800	800
RIDEAU RIVER				
Merrickville	2	1915-19	900	800
MUSKOKA RIVER				
Ragged Rapids	2	1938	7,500	7,500
Big Eddy	2	1941	7,100	7,100
SOUTH MUSKOKA				
South Falls	3	1916-25	4,200	4,000
Trethewey Falls	1	1929	1,600	1,600
Hanna Chute	1	1926	1,200	1,200

Table A.2 Summary of Hydraulic Resources Installed and Authorized – East System **(continued)**

Generating station	Number of units	First power dates	December peak resources Median (kW)	Dependable (kW)
BEAVER RIVER				
Eugenia	3	1915-20		
	1	O/S 1970		
Total			3,500	3,500
SEVERN RIVER				
Big Chute	4	1911-19	4,300	4,300
ABITIBI RIVER				
Abitibi Canyon	5	1933-59	294,000	294,000
Otter Rapids	4	1961-3	179,000	177,000
MATTAGAMI RIVER				
Little Long	2	1963	128,000	125,000
Harmon	2	1965	134,000	129,000
Kipling	2	1966	142,000	142,000
Wawaitin	4	1912-18	10,800	10,700
Sandy Falls	3	1911-16	2,700	2,600
Lower Sturgeon	2	1923	6,000	5,900
MISSISSAGI RIVER				
Aubrey Falls	2	1969	158,000	158,000
George W. Rayner	2	1950	46,000	46,000
Wells	2	1970	229,000	229,000
Red Rock Falls	2	1960-61	40,000	40,000
MONTREAL RIVER				
Lower Notch	2	1971	267,000	253,000
Indian Chute	2	1923-4	3,000	2,900
Hound Chute	4	1910-11	3,600	3,400
MATABITCHUAN RIVER				
Matabitchuan	4	1910	10,000	10,000
SOUTH RIVER				
Elliott Chute	1	1929	1,200	1,200
Bingham Chute	2	1923-4	900	900
Nipissing	2	1921-4	1,600	1,600
STURGEON RIVER				
Crystal Falls	4	1921	8,200	7,600
WANAPITEI RIVER				
Stinson	2	1925	5,700	5,700
Coniston	3	1905-15	4,200	4,200
McVittie	2	1912	2,100	1,800

Table A.3 Summary of Thermal Resources Installed and Authorized – East System

Generating station	Number of units	First power dates	Maximum continuous rating (kW)	Peak resources (kW)
CONVENTIONAL FOSSIL-FUELLED				
R.L. Hearn	4	1951-3	384,000	
	4	1959-61	758,000	
Total			1,142,000	1,179,000[a]
J.C. Keith[b]	4	1951-3	254,000	256,000
Lakeview	8	1961-8	2,296,000	2,296,000
Lambton	4	1969-70	1,980,000	2,100,000
Nanticoke	8	1972-8	3,920,000	4,248,000
Lennox	4	1975-7	2,140,000	2,232,000
Wesleyville[c]	2	1990	990,000	1,082,000
COMBUSTION TURBINES[d]				
R.L. Hearn	3	1967		22,000
Lakeview	3	1967		22,000
Lambton	3	1967		22,000
Lennox	2	1975		5,000
J.C. Keith[e]	1	1967		7,000
Sarnia-Scott	4	1965-6		71,000
Detweiler	4	1967		75,000
A.W. Manby	4	1965-6		78,000[f]
Pickering A	6	1971-3		46,000
Bruce A	4	1974-6		56,000
Nanticoke	3	1971		22,000
Bruce HWP	3	1976		42,000
Pickering B	6	1980-81		46,000
Bruce B	4	1981-3		56,000
Wesleyville	2	1981		5,000
Darlington	4	1983-5		56,000
NUCLEAR				
Nuclear Power Demonstration[g]	1	1962	22,000	22,000
Douglas Point[h]	1	1967	206,000	206,000
Pickering A	4	1971-3	2,060,000	2,060,000
Pickering B	4	1981-3	2,064,000	2,064,000
Bruce A	4	1976-8	2,960,000	2,960,000
Darlington	4	1987-90	3,524,000	3,524,000
Bruce B	4	1983-7	3,024,000	3,024,000

Notes:

a) Limited to 1,164,000 kW until June 1979 and to 1,171,000 kW until June 1980.

b) Unavailable until June 1, 1980.

c) Although Wesleyville is a part of Ontario Hydro's committed programme, its construction has been stopped and the equipment has been stored until 1990.

d) The exact in-service dates for combustion turbines at the Bruce B, Wesleyville, and Darlington sites are not known due to recent deferrals.

e) Temporarily unavailable.

f) Limited to 58,500 kW.

g) Ontario Hydro purchases steam from Atomic Energy of Canada Ltd., which owns the nuclear part of the station.

h) Ontario Hydro purchases electricity from AECL, which owns the entire station.

Table A.4 Ontario Primary Demands and Total Resources - West System[a]

	Ontario primary demand				December dependable peak resources					
		Annual energy								
	December peak(MW)	GWh	Average MW	Annual load factor(%)[b]	Hydraulic (MW)	Fossil steam (MW)	Nuclear (MW)	Purchase (MW)	Combination turbine (MW)	Total dependable (MW)
1935	52.3	334.3	68.1	75.0	0	0	0	0	75.0	
1936	64.9	396.0	45.1	67.9	88.2	0	0	0	0	88.2
1937	69.5	492.0	56.2	78.1	93.9	0	0	0	0	93.9
1938	69.4	450.0	51.4	65.8	90.8	0	0	0	0	90.8
1939	73.0	485.5	55.4	67.1	89.6	0	0	0	0	89.6
1940	79.4	570.0	64.9	72.5	87.3	0	0	0	0	87.3
1941	91.4	620.8	70.9	76.8	87.4	0	0	0	0	87.4
1942	89.1	617.4	70.5	79.1	88.0	0	0	0	0	88.0
1943	100.7	606.1	69.2	68.7	89.5	0	0	0	0	89.5
1944	96.1	663.3	75.5	74.7	88.5	0	0	0	0	88.5
1945	103.9	688.5	78.6	75.4	103.0	0	0	0	0	103.0
1946	114.1	784.0	89.5	76.8	105.3	0	0	0	0	105.3
1947	127.3	855.9	97.7	76.7	109.4	0	0	0	0	109.4
1948	147.8	963.2	109.7	74.2	129.2	0	0	0	0	129.2
1949	185.7	1,184.3	135.2	71.7	175.7	0	0	0	0	175.7
1950	199.1	1,298.9	148.3	74.5	232.0	0	0	0.6	0	232.6
1951	213.0	1,415.5	161.6	75.5	234.0	0	0	1.1	0	235.1
1952	225.4	1,491.0	169.7	73.3	59.8	0	0	1.4	0	261.2
1953	240.0	1,571.7	179.4	74.8	261.1	0	0	1.8	0	262.9
1954	266.6	1,655.7	189.0	69.6	290.5	0	0	2.1	0	292.6
1955	328.6	2,011.5	229.6	69.6	315.2	0	0	2.2	0	317.4
1956	356.7	2,264.9	257.8	72.3	368.1	0	0	2.7	0	370.8
1957	406.9	2,537.0	289.6	71.2	366.0	0	0	3.3	0	369.3
1958	448.8	2,713.8	309.8	69.0	528.6	0	0	1.7	0	530.3
1959	427.9	2,760.8	315.2	69.9	593.9	0	0	1.7	0	595.6
1960	421.4	2,759.0	314.1	72.5	593.9	0	0	2.0	0	595.9
1961	422.4	2,690.1	307.1	72.2	593.5	0	0	3.0	0	596.5
1962	435.7	2,752.2	314.2	72.1	593.5	0	0	0	0	593.5
1963	445.5	2,771.7	316.4	71.0	593.5	93.0	0	0	0	686.5
1964	464.9	2,987.9	340.2	73.2	593.5	93.0	0	0	0	686.5
1965	474.1	3,112.4	355.3	74.5	593.5	93.0	0	0	0	686.5
1966	537.4	3,593.5	410.2	76.3	585.8	93.0	0	0	0	678.8
1967	562.7	3,795.1	433.2	77.0	585.8	100.0	0	0	0	685.8
1968	606.9	4,016.8	457.3	75.3	580.5	100.0	0	0	29.0	709.5
1969	630.9	4,343.8	495.9	78.6	580.5	100.0	0	0	29.0	709.5
1970	682.4	4,598.2	524.9	76.9	578.6	100.0	0	0	29.0	707.6
1971	686.8	4,736.0	540.6	78.4	578.6	100.0	0	0	29.0	707.6
1972	753.4	5,009.7	570.3	75.7	579.1	100.0	0	50.0	29.0	758.1
1973	752.6	5,115.2	583.9	77.3	579.1	100.0	0	100.0	29.0	808.1
1974	722.7	5,306.8	605.8	80.4	579.1	100.0	0	200.0	29.0	908.1
1975	560.8	4,709.3	537.6	73.0	578.7	97.0	0	200.0	29.0	904.7
1976	859.4	5,286.9	601.9	70.0	578.7	97.0	0	200.0	29.0	904.7
1977	845.1	5,888.8	672.2	78.0	578.7	97.0	0	100.0	29.0	804.7
1978	790.8	5,801.7	662.3	78.2	578.7	97.0	0	150.0	29.0	854.7

Notes:

a) The Kaministiquia Power Co. demand and resources are not included in the West System for the years 1935 to 1950.

b) The annual load factor ib calculated on the basis of the annual peak, which is not necessarily identical to the December peak.

Table A.5 Summary of Hydraulic Resources Installed and Authorized – West System

Generating station	Number of units	First power dates	December peak resources: Median (kW)	December peak resources: Dependable (kW)
NIPIGON RIVER				
Pine Portage	4	1950-54	127,200	114,800
Cameron Falls	7	1920-58	75,600	75,000
Alexander	5	1930-58	62,400	62,400
ENGLISH RIVER				
Ear Falls	4	1930-48	17,800	11,100
Manitou Falls	5	1956-8	63,900	59,600
Caribou Falls	3	1958	86,100	81,400
WINNIPEG RIVER				
Whitedog Falls	3	1958	68,200	61,500
KAMINISTIKWIA RIVER				
Silver Falls	1	1959	46,800	45,700
Kakabeka Falls	4	1906-14	23,600	18,600
AGUASABON RIVER				
Aguasabon	2	1948	45,200	45,000

Table A.6 Summary of Thermal Resources Installed and Authorized – West System

Generating station	Number of units	First power dates	Maximum continuous rating (kW)	Peak resources (kW)
CONVENTIONAL FOSSIL-FUELLED				
Thunder Bay	3	1962-81	391,000	395,000
Atikokan	2	1984-8	412,000	412,000
COMBUSTION TURBINES				
Thunder Bay	2	1968		29,000

APPENDIX B

Summary of Characteristics of Conventional Generation Technologies

This appendix outlines the characteristics – cost, reliability and performance, operating characteristics, and fuel (and heavy water for CANDU plants) requirements – of the conventional electricity generation technologies used in Ontario. These characteristics affect the choice of a generating mix and thus the long-range expansion of the system. The factors related to the socio-environmental impact of these technologies, and various characteristics of the conventional as well as the alternative supply technologies, are dealt with in separate volumes.

CANDU Nuclear Generation

High capital costs, the use of heavy water both as moderator and primary coolant, and the use of natural uranium as the primary fuel are the most significant features of CANDU nuclear generation. Ontario Hydro's long-range plans are based on the installation of four-unit CANDU nuclear stations, ultimately, to provide most of the base-load generation, except for what is provided by hydroelectric capacity. Continued installation of new CANDU reactors carries with it the need to ensure adequate supplies of capital, heavy water, and uranium.

In the period up to 2000, the nuclear generating units most likely to be used are 500-600 MW units similar to those at the Pickering Generating Station (GS) and 750-850 MW units similar to those at the Bruce GS. To reduce the transmission requirements and the associated power and energy losses, Ontario Hydro plans to locate the new stations as close as possible to load centres but outside densely populated areas (an example is the Pickering GS). Also, to ensure adequate supplies of natural cooling water, these stations would probably be located on the shores of the Great Lakes and the Ottawa and St. Lawrence rivers.

Cost

The capital cost of CANDU nuclear stations is, and is expected to continue to be, considerably higher than the capital cost of other conventional steam-thermal plants. A study entitled "Life Cycle Costs of Coal and Nuclear Generating Stations", made for the Commission by Dr. S. Banerjee and Dr. L. Waverman in July 1978, obtained the following capital-cost components for one generating unit of a 4 × 850 MW nuclear station to be in service in 1985.

1. Direct, indirect, and engineering costs (including escalation) – $785/kW
2. Interest during construction – $308/kW
3. Subtotal – $1,093/kW
4. Contingencies – $70/kW
5. Heavy water – $240/kW
6. Total capital costs – $1,403/kW
7. Contingencies for regulatory approval delays, etc. – $24/kW
8. Imputed R&D costs – $70/kW
9. Security costs – $3/kW
10. Total cost – $1,500/kW

Items 7, 8, and 9, unique to the CANDU programme, are added to the usual capital cost. The R&D cost component of about $70/kW is based on estimated R&D costs to date of $1.2 billion, distributed over 17,000 MW of generating capacity. In addition, an allowance of about $80 million, or $24/kW, was made for contingencies related to regulatory and environmental processes of the sort that may delay the construction schedule of a 4 × 850 MW station. The security costs, which are negligible, are added to show how small they are.

Fig. B.1: p. 122 Figure B.1 shows Ontario Hydro's estimates of the capital costs of CANDU, fossil-steam, and combustion turbine stations to be in service in 1985. Although Ontario Hydro's estimates of the capital costs of an 850 MW nuclear station cannot be compared directly with the estimates of Banerjee and Waverman because of different assumptions, it is evident that they are in the same order. Figure B.1 also indicates

the economies of scale, that is, the way the cost per kilowatt decreases as the size of the units is increased. The economies of scale of larger units are to a certain extent offset by their lower capability factors as well as by the higher reserve requirements associated with their greater size. This has been discussed in Chapter 3.

The annual O&M costs for the 4 × 850 MW station were estimated in the Banerjee and Waverman study to be: operating labour – \$5.72/kW; operating materials – \$3.43/kW; heavy water upkeep – \$3.26/kW; and additional security force – \$2.35/kW;[1] totalling \$14.76/kW in 1985 dollars. Figure B.2 shows Ontario Hydro's estimates of total O&M costs for various types of generation over a range of unit sizes and annual capacity factors (ACF). Fig. B.2: p. 12

Uranium prices began a dramatic rise early in 1973, following the quadrupling of oil prices. The spot price for uranium in U.S. dollars increased from \$16/kg in the early 1970s to about \$110/kg early in 1978. In terms of electricity generation costs, this is equivalent to an increase from \$0.3/MW·h to \$2.2/MW·h. However, Ontario Hydro, through forward contracts, has been able to keep its uranium cost increases during the same period to approximately 11 per cent per annum. The fuelling cost for Pickering GS in 1976 was about \$1.2/MW·h. The uranium fuel costs assumed in the Banerjee and Waverman study are in the range of \$4/MW·h to \$5/MW·h in 1985, which is the first year of operation.

Reliability and Performance

Ontario Hydro's estimates of long-run average capability factors of the 500 MW and 850 MW units are 80 per cent and 77 per cent, respectively (Table B.1). These are mature values, attainable after a unit has been in service for three or four years; the capability factors in the first year of service are expected to be only 68 per cent and 66 per cent, respectively. Since CANDU reactors allow on-power refuelling, their annual capability tends to be higher than that of the U.S. light-water reactors. The performance of Pickering A has been outstanding since its commissioning in 1971; some of its units have achieved annual capabilities of more than 90 per cent (see Table 3.4 in Chapter 3). The average lifetime capability of Pickering A to date is about 77 per cent.

Table B.1 Ontario Hydro's 1975 Forecast of New Generating Unit Availability Indices

	CANDU nuclear units		Fossil steam units: Lignite		Fossil steam units: Bituminous coal or oil		Combustion turbine units	Hydraulic units
	500MW	850MW	150/200MW	300MW	500MW	750MW		
Adjusted forced outage rate (AFOR) (%)								
1st year of operation	15	15	15	15	15	17	15	0.5
2nd	12	13	13	13	12	15	15	0.5
3rd	10	12	11	11	10	13	15	0.5
4th	9	10	9	9	8	10	15	0.5
5th	9	10	9	9	8	10	15	0.5
Maintenance outage factor (MOF) (%)								
1st year of operation	8	8	6	6	6	7	included	included
2nd	6	6	5	5	4	5	in	in
3rd	4	4	4	4	4	5	POF	POF
4th	4	4	4	4	4	5		
5th	4	4	4	4	4	5		
Planned outage factor (POF) (%)								
1st year of operation	12	14	12	12	15	15	10	4
2nd	10	10	10	10	12	12	10	4
3rd	8	10	8	10	10	10	10	4
4th	8	10	8	10	10	10	10	4
5th	8	10	8	10	10	10	10	4
Capability factor (%)								
1st year of operation	68.0	66.3	69.7	69.7	67.2	64.7	76.5	95.5
2nd	73.9	73.1	74.0	74.0	73.9	70.6	76.5	95.5
3rd	79.2	75.7	78.3	76.5	74.4	74.0	76.5	95.5
4th	80.1	77.4	80.1	78.3	79.1	76.5	76.5	95.5
5th	80.1	77.4	80.1	78.3	79.1	76.5	76.5	95.5

Source: Ontario Hydro, "Generation Planning Processes," Submission to RCEPP, May 1976, Exh. 21.

However, a recent discovery of pressure tube stretching at the four Pickering A units and the first three of the Bruce A units will probably require each of these units to be taken out of service for one year between 1985 and 1992, for retubing. Some of the tubes had stretched about twice as much as had been expected. This may result in a slight reduction of the expected lifetime capability of these units. Ontario Hydro believes that such a problem will not occur in any future reactors.

Operating Characteristics

CANDU nuclear units as now designed can be rapidly shut down and started up. However, this capability is affected by inherent limitations in the reactor that can cause it to "poison out" (i.e., to experience an excessive buildup of neutron-absorbing substances), and thereby be unavailable for up to 36 hours, in some circumstances. This can occur, for instance, after a rapid shut-down from full load, if the unit is not then quickly reloaded to a high level (typically in from 20 to 40 minutes). The likelihood of a poison-out occurring, and the duration of a poison-out, depend, in general, on the design of the reactor and, in particular, on the rate of shut-down and start-up. With the CANDU reactor design that is used by Ontario Hydro, operation at full load during the daytime with a scheduled overnight shut-down is impossible, but night-time output can be lowered to about 50 per cent of the daytime output. On weekends the units can be operated at fixed lower levels or shut down completely on a scheduled basis. These CANDU units, however, are not suitable for load-following on an hour-to-hour basis.

Because of their operating characteristics and their low fuelling costs, CANDU units will be operated essentially at base-load capacity factors for the foreseeable future. Eventually, it might be necessary during nights and weekends either to operate them at reduced output or to "charge" energy storage systems.

Uranium Requirements

A CANDU reactor operating at 75 per cent annual capacity factor requires 130 kg of uranium per megawatt annually. Thus, the lifetime (30 years) requirement per megawatt of capacity is approximately 4 tonnes. The present Ontario Hydro CANDU capacity of about 5,000 MW needs about 650 tonnes of uranium per year. The Canadian uranium resource estimates for 1978 are shown in Table 3.5 in Chapter 3. Most of Canada's uranium resources lie in Ontario and Saskatchewan. A very large proportion of Canada's production is currently being exported to Europe and Japan. Existing export commitments, up to 1993, amount to 62,000 tonnes of Ontario's resources and 11,400 tonnes of Saskatchewan's resources. The uranium supply and demand situation for Ontario Hydro's programme is discussed in more detail in Chapters 3 and 7. It is shown that Hydro's existing contracts are sufficient for the 30-year requirements of about 5,400 MW of nuclear capacity beyond its currently committed programme.

Heavy-Water Requirements

The demand for heavy water by Ontario Hydro consists of central inventory demand (moderator and primary coolant) for reactors being commissioned, and make-up demand for losses during operation. The initial requirement is approximately 1 tonne of heavy water per megawatt of installed capacity for a 500 MW unit, and 0.9 tonnes/MW for an 850 MW unit. The annual loss during operation is about 5 tonnes for each nuclear unit.

Heavy-water plants currently existing and under construction in Ontario include the Bruce Heavy Water Plants (BHWP) A, B, and D. BHWP-A came into service in June 1973 and BHWP-B is expected to be in service by March 1980. The demonstrated capacity of BHWP-A is 100.6 kg/hour. The annual production depends on the annual capacity factor. The 1976, 1977, and 1978 capacity factors for BHWP-A were 91 per cent, 74.5 per cent, and 80 per cent, respectively. Ontario Hydro classifies the annual supply as "dependable" (with a 90 per cent chance of being exceeded and corresponding to a 63 per cent annual capacity factor), "probable" (with a 50 per cent chance of being exceeded and corresponding to a 73 per cent ACF), or "optimistic" (with a 10 per cent chance of being exceeded and corresponding to an 80 per cent ACF). The annual output of BHWP-A under these three conditions will be 550, 640, and 700 tonnes, respectively. Both BHWP-B and BHWP-D were designed for the same capacity as BHWP-A, but in January 1979 Ontario Hydro announced the cancellation of half of BHWP-D in the face of recent lower estimates of growth in its nuclear capacity. The total dependable

output of the three plants could support the construction of about 1,400 MW of nuclear capacity annually between 1981 and 2000, or approximately 20,000 MW beyond the currently committed programme.

Fossil-Steam Generation

The most commonly used fossil fuels for steam-electric generation are high- or low-quality coal, residual oil, and natural gas. Ontario Hydro's currently operating fossil-steam capacity is coal-fired, with the exception of the residual-oil-fired 2,200 MW Lennox GS and the 1,200 MW Hearn GS, which is partly fired by natural gas due to air quality constraints. Except for the currently committed 2 × 540 MW Wesleyville residual-oil-fired plant, Hydro's planned fossil-steam capacity is based on coal supplies from the U.S. and western Canada. The current mix of Ontario Hydro's fossil-steam resources is:

	Peak capacity (MW)	1978 Energy generation (GW·h)
Coal-fired	8,965 (76%)	27,073 (87%)
Oil-fired	2,200 (19%)	1,739 (6%)
Gas-fired	600 (5%)	2,079 (7%)
Total	11,765	30,891

The unit size of the coal-fired stations planned for the East System is 750 MW, and it is expected that these stations will be located on the shores of the Great Lakes and the Ottawa and St. Lawrence rivers, outside densely populated areas but as close to load centres as possible.

Cost

The capital cost per kilowatt of fossil-steam plants is much lower than that of CANDU nuclear plants. The Banerjee and Waverman study obtained the following cost estimates for a 4 × 750 MW coal-fired station coming into service in 1985.

1. Direct and indirect (including escalation) – $712/kW
2. Interest during construction – $158/kW
3. Subtotal – $870/kW
4. Subtract cost of scrubbers – $92/kW
5. Total cost – $778/kW

Items 1 and 2 are estimates for a plant with scrubbers, and, since environmental policies in Ontario do not require the use of scrubbers, these costs are removed. Ontario Hydro's capital-cost estimates are shown in Figure B.1, which also indicates that the economies of scale beyond the 750 MW unit size are marginal.

The capital costs of a gas-fired steam-thermal station are approximately 20 per cent lower than those for a coal-fired station, because the gas-fired station has virtually no pollution control equipment, there are no storage requirements, and the boiler furnace is smaller. An oil-fired station's capital costs lie somewhere between those of a coal-fired station and those of a gas-fired station, and depend on the quality of oil used and the storage requirements. Unlike natural gas, residual oil may contain much particulate matter and thus may require the use of electrostatic precipitators.

The above arguments also hold for comparisons of the operations and maintenance costs of the three fossil-steam options; the costs are highest for coal, lowest for gas, and intermediate for oil. The costs for a 4 × 750 MW coal-fired station were estimated by Banerjee and Waverman to be about $9/kW per year ($4.9/kW for labour and $4.1/kW for materials) in 1985 dollars. Ontario Hydro's estimates, which are comparable to the Banerjee and Waverman estimates, are shown in Figure B.2.

Ontario Hydro's current supply of coal (about 10 million tonnes per year) is primarily from the Appalachian region in the eastern United States, although arrangements have been made to develop a long-term western Canadian coal supply to supplement U.S. deliveries (see Chapter 3). The price of U.S. coal has increased dramatically from about $10/tonne in 1970 to about $37/tonne in 1978. Ontario Hydro's current fuelling cost for coal-fired stations is approximately $15/MW·h. The current fuelling costs for the Lennox oil-fired station and for Hearn's gas-fired units are about $34/MW·h and $29/MW·h, respectively. Hydro's most efficient fossil-steam plants are the coal-fired Lambton GS and oil-fired Lennox GS, with thermal efficiencies of 37.2 per cent and 37.6 per cent, respectively.

Reliability and Performance

If fossil-steam units are to be used for intermediate and peak loads, the planned and maintenance outage components of unit incapability should not significantly affect unit reliability. This is because maintenance is done during low-load periods when the output of such units may not be required. Ontario Hydro's estimates of the capability factors of 500 MW and 750 MW fossil-steam units (79 per cent and 76.5 per cent, respectively) are comparable to the corresponding CANDU units, as are the forced outage rates (Table B.1).

Operating Characteristics

Small fossil-steam units, operating at lower temperatures and pressures, can be loaded and unloaded rapidly and can be shut down at night without adversely affecting their reliability. Large units operating at high temperatures and pressures are not as flexible. One way to get around this is to install a steam bypassing system to permit better control of steam temperature and pressure – the viability of such an arrangement, however, is not well established.

Large fossil-steam units can be operated at minimum safe loadings during periods of low system demand. These loadings are below the 50 per cent value that applies to the present CANDU nuclear units used by Ontario Hydro. Part-load operation for extended periods, however, is quite inefficient.

Ontario Hydro's existing fossil-steam capacity is utilized for all four modes of operation (base, intermediate, and peak load, as well as reserve). This pattern is expected to continue in the future, although the base-load role of coal-fired stations will decline as new nuclear capacity is added to the system. Hydro's new coal-fired capacity is planned essentially for intermediate-load applications.

Fuel Requirements

A modern 1,000 MW fossil-steam plant operating at 60 per cent annual capacity factor requires approximately the equivalent of 1.8 million tonnes of bituminous coal, or 8.6 million barrels of residual oil, or 50 billion cubic feet of natural gas per year. Of course, if the assumed capacity factor is 30 per cent, the requirements will be half as much. In 1978, Ontario Hydro's fossil-steam electricity generation required 9 million tonnes of coal, 3 million barrels of residual oil, and 25 billion cubic feet of natural gas.

Ontario Hydro's existing contracts for coal from U.S. sources are for an annual supply of 5.5 million tonnes with the Consolidated Coal Company (expiring in 1986), 2.3 million tonnes with the Eastern Associated Coal Corporation (expiring in 1984), 2.7 million tonnes with the U.S. Steel Corporation (expiring in 2008), and 1.6 million tonnes with other companies (expiring in 1980). Hydro has recently contracted for about 2.5 million tonnes per year of bituminous coal from new mines in Alberta and British Columbia and 0.9 million tonnes per year of lignite from Saskatchewan. The lignite is for use at the new generating units being installed at Thunder Bay, in the West System. The western Canadian bituminous coal is of lower quality than the U.S. coal and the design of existing coal-fired stations requires that the western Canadian coal be blended with the U.S. coal before being burned. Ontario Hydro has such a blending facility in operation at its 8 × 500 MW Nanticoke GS on Lake Erie.

The existing supply of 5 million barrels of residual oil per year is from the Golden Eagle refinery near Quebec City, utilizing Venezuelan and Middle Eastern crude. This contract expires in 1979 and Ontario Hydro has signed a 15-year contract (1977 through 1991) with Petrosar Ltd. to supply 7.3 million barrels of low-sulphur residual oil per year using western Canadian crude. The contract is renewable for three-year periods after 1991. However, faced with reduced load forecasts, Hydro hopes to reduce the annual supply by half. For the needs of the Hearn GS, Hydro had contracted with Consumers' Gas Company for 49 billion cubic feet of natural gas per year until November 1981. Again because of lower demand, Hydro's forecast consumption of natural gas is only 10 billion cubic feet per year until the late 1980s.

Gas Turbine Generation

Gas turbine units are available in a wide range of sizes, from under 5 MW up to 100 MW. Larger sizes of gas turbine generating units can be devised by coupling two or more gas turbines to drive a single generator. Ontario Hydro's current gas turbine generating capacity is roughly 500 MW. Most of this capacity is located at thermal generating stations, so that in addition to providing peaking capability to the system as a whole, the units can be used to provide stand-by power for shutting down or starting up these stations.

Gas turbines require high quality, clean, premium fuels – Ontario Hydro uses No. 2 fuel oil – because the fuel is combusted and expanded inside the turbine and so must contain few impurities. This allows the turbines to be located close to load centres, which means less associated transmission and voltage control equipment.

Cost

The capital costs of gas turbine units tend to be much lower than those of fossil-steam generating units. Ontario Hydro's estimates (see Figure B.1) indicate that the capital costs in 1985 dollars could be anywhere between \$350/kW and \$500/kW, depending on the size. Factors facilitating the low capital costs of gas turbine units include the fact that supplies of cooling water are not needed, construction lead times are short (one year), and no steam generating equipment is required.

Operating labour requirements are much lower than for fossil-steam stations, but, depending on the type of operation and the type of fuel used, maintenance costs may be quite high. For relatively continuous operation using natural gas as the fuel, maintenance costs are low, but, for intermittent operation using distillate oil, reliability may be poor and maintenance cost may increase. Figure B.2 shows that the operations and maintenance costs of gas turbines vary significantly with the operation.

Because premium fuels are used, the fuelling costs of gas turbines tend to be high. No. 2 fuel oil used by Ontario Hydro currently costs about \$40/MW·h. Natural gas works out at about \$30/MW·h.

Reliability and Performance

Gas turbines suffer from the fact that their efficiency, and thus their output, decreases significantly as the temperature of the ambient air, which is their heat sink, rises. Therefore, their capability is much lower in summer than in winter. Their reliability is also affected by the type of operation and the type of fuel used. The reliability of units operating relatively continuously and using natural gas is good. For intermittent operation using distillate oil, it tends to be poor. Ontario Hydro's estimate of a gas turbine unit's capability is 76.5 per cent – the forced outage rate is 15 per cent and the maintenance outage is nearly 10 per cent. The forced outage is significantly higher than with large steam-thermal units (Table B.1).

Operating Characteristics

The operating flexibility of gas turbine units is not as high as that of hydroelectric units, but is higher than that of nuclear and fossil-steam units. These units are capable of being started up and shut down on relatively short notice, and can therefore be shut down overnight as required. However, frequent start-ups and shut-downs increase their maintenance costs. Since the operation of gas turbines at reduced output is very inefficient, it is preferable to run them close to rated load or shut them down. Some units can be operated at outputs in excess of their rated load for short durations. Operating them this way tends to increase their maintenance costs.

In Ontario Hydro's system, gas turbines are used primarily as reserve capacity or peak capacity, or as stand-by capacity at thermal generating stations for shutting them down and starting them up in emergencies.

Fuel Requirements

Because of their lower thermal efficiency (in the order of 30 per cent), gas turbines require a somewhat higher quantity of fuel, compared with fossil-steam units, to generate the same amount of electricity. A 50 MW gas turbine station operating at a 10 per cent annual capacity factor will require approximately 10,000 barrels of No. 2 oil or 50 million cubic feet of natural gas annually.

Hydroelectric Generation

Until the early 1950s, Ontario Hydro's electric power system was based entirely on hydraulic generation, which even today supplies roughly one-third of the province's total electricity requirements. Hydro's hydraulic capacity is about 6,400 MW, distributed among 70 stations varying in size from about 1 MW to 1,400 MW. Since the operating costs of hydraulic plants are low, they are virtually unaffected by inflation, once built. Another important characteristic of hydroelectric units is their excellent operating flexibility. The siting of a hydroelectric generating station is limited largely by

natural conditions of topography, geology, and rainfall. Some degree of flexibility is possible by the use of water-storage developments, water diversions, tunnels, and canals.

Cost

Because the design of hydroelectric projects varies greatly from one site to another, it is not possible to state typical capital costs for hydroelectric developments. Generally speaking, the capital costs per kilowatt are lower for large installations, and for installations with large heads of water. Capital costs tend to be high compared with those of large fossil-steam generating units. A study by Energy, Mines and Resources Canada in 1978 estimated the generation capital costs of the James Bay project in Quebec and the Gull Island project in Labrador to be \$691/kW and \$412/kW, respectively, in 1976 dollars. This compares with \$739/kW for a CANDU nuclear station (750 MW units) and \$375/kW for a coal-fired station (750 MW units).

Most of the potential hydroelectric sites in southern Ontario have been developed and the remaining sites are in remote areas of northern Ontario on rivers flowing into James Bay. The additional capital costs for transmission lines, and associated power and energy losses that would occur in bringing this power to southern Ontario loads, would increase the total unit capital cost of hydroelectric projects in Ontario and thus make them economically less attractive. The operations and maintenance costs of hydroelectric stations are quite low, however, compared with those of fossil-steam generation, and fuel costs are negligible, consisting entirely of the water-rental charges levied by the government. For the Ontario Hydro system, the average O&M and water-rental charges are approximately \$1/MW·h and \$0.5/MW·h, respectively.

Reliability and Performance

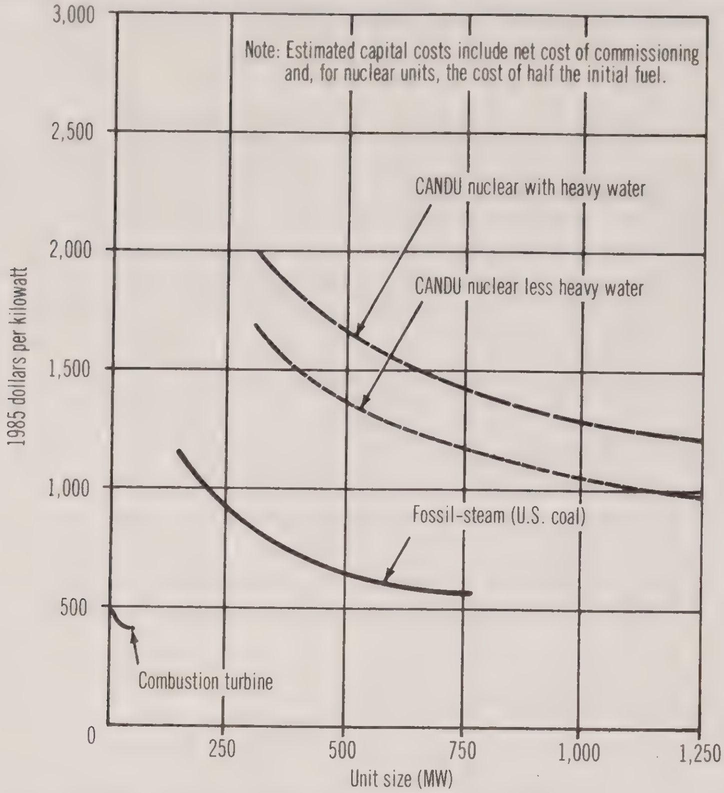
Mechanically and electrically, hydraulic units are exceptionally reliable. Ontario Hydro's estimates of the average forced outage rate and maintenance requirements of its hydraulic units are 0.5 per cent and 4 per cent, respectively, resulting in a capability of 95.5 per cent (Table B.1). However, the availability, or actual peak power production capability, may be adversely affected by variations in water supply and wind, and by ice formation. The supply reliability may also be reduced by the long transmission lines.

Operating Characteristics

Hydroelectric generating units can be started up and shut down, and loaded and unloaded, quickly. Therefore, they are most appropriate for following the daily and weekly variations in system load. While operating them at reduced output is generally satisfactory, some units may be very inefficient at low loadings. Therefore, in a large system such as Ontario Hydro's, it is preferable to run them at full output or shut them down.

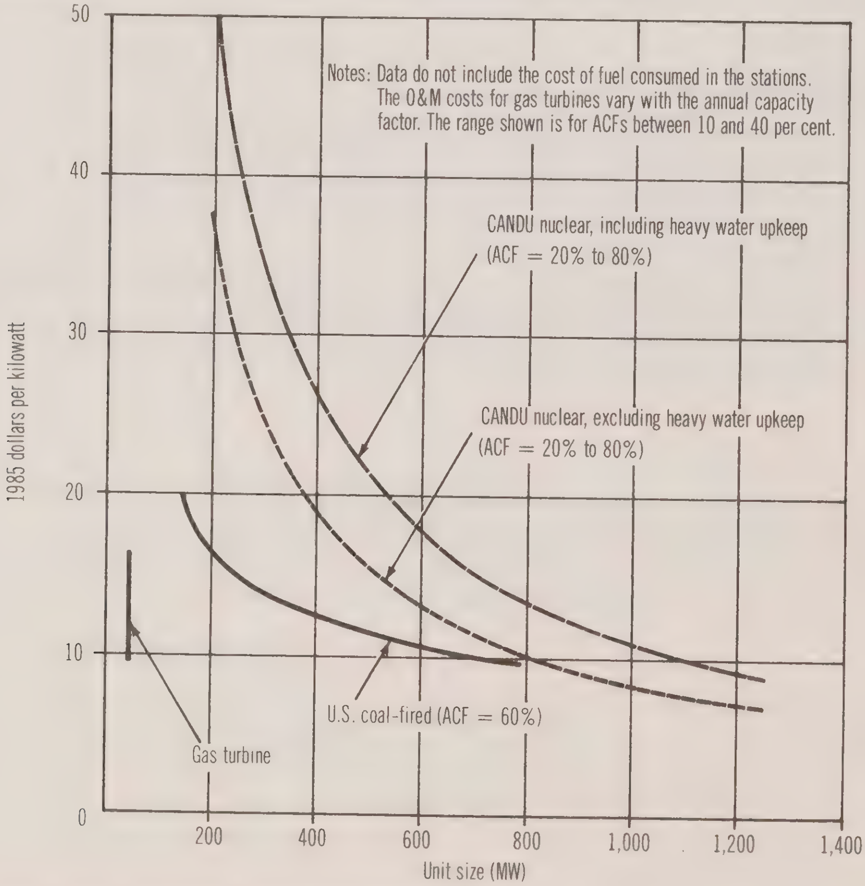
Because of their good operating characteristics, hydroelectric units can be individually designed and operated in any of the four operating modes: base load, intermediate load, peaking, or reserve. The choice of a particular mode of operation is determined by the natural features of the site and the cost of developing it.

Figure. B.1 Thermal Generation, Estimated Capital Cost of Nominal Capacity Coming into Service in 1985 (4-Unit Generating Stations)



Source: "Generation Planning Processes", Ontario Hydro submission to RCEPP, May 1976, Exhibit 21.

Figure. B.2 Thermal Generation, Estimated Annual Operations and Maintenance Costs (4-Unit Generating Stations)



Source: "Generation Planning Processes", Ontario Hydro submission to RCEPP, May 1976, Exhibit 21.

APPENDIX C

Some Technical Considerations Related to Ontario's Interconnections

The Ontario system and all its neighbouring systems except that of Quebec normally operate in synchronism with each other with all tie lines closed. This has the advantage that mutual assistance is immediately and atuomatically possible in an emergency. However, it carries with it the risk that, if one utility is blacked out, it may carry its neighbours with it, as in the 1965 blackout. The National Electric Reliability Council (NERC) is a voluntary association of Canadian and American utilities that establishes, and monitors adherence to, system performance criteria designed to prevent this eventuality.

When electricity utility systems operate in synchronism, power transfers can be made with considerable flexibility. For instance, if it is desired to transfer power from Ontario Hydro to Detroit Edison, this can be achieved, within broad limits imposed by transmission system capabilities, by increasing the output of a generating station on the Ontario Hydro system, and decreasing the output of a generating station on the Detroit Edison system, by the desired amount. However, it is not possible to maintain perfectly smooth and steady control, and random, inadvertent transfers occur. The interconnections must be of reasonable capacity in relation to the sizes of the systems in order to accommodate inadvertent exchanges as well as leave an ample margin for productive uses.

The transfer capability of an interconnection depends not only on its own capability to carry power, but upon the point in each system to which it is joined and the capability of the system beyond that point to transmit power to or from the interconnection. In theory, the most flexible interchange capability is achieved by making the interconnection between the main load centres of each system since this should best ensure that transfers are not restricted by bottlenecks in the main systems. This is seldom practicable, however, and it is usually necessary to establish the shortest feasible interconnection between suitable adjoining points on the perimeters of the grid systems. With such a configuration, the transfer capability varies with the patterns of loads and generation and with the directions of the transfer. Export capability is high from a perimeter interconnection when the load is low and the generation is high in the vicinity of the interconnection. Import capability is high when the situation is the reverse.

When two systems are interconnected at two points at some distance from each other, there will in general be a natural circulation of power around the two systems that may overload some transmission elements of a utility and restrict their use. Circulating power around the Great Lakes, Lake Ontario and Lake Erie in particular, is a notable example of this phenomenon. The problem of circulating power can be mitigated by installing a phase-shifting transformer in an interconnection, as Ontario Hydro has done at Cornwall, Windsor, and Whiteshell, Manitoba.

In Quebec, hydroelectric power is transmitted from Churchill Falls and James Bay to Quebec City and Montreal over long and heavily loaded lines. These impose stability limitations that preclude operating the Hydro-Québec system in synchronism with its neighbours. To transmit power to Ontario Hydro, Hydro-Québec must disconnect a generator from its own system and connect it to the Ontario Hydro system via one of the interconnections. For Ontario Hydro to transmit power to Hydro-Québec, the same process is used, in reverse.

This procedure is inflexible and provides limited options for power transfers between Ontario and Quebec. For many years the main transfers comprised firm power deliveries to Ontario Hydro that were effected by isolating generation at Hydro-Québec's Beauharnois plant and connecting it to the Ontario Hydro system. This practice has been superceded by an arrangement under which Beauharnois supplies the Power Authority of the State of New York in the summer months and is reconnected to the Hydro-Québec system in the winter months.

A more flexible interconnection could be made between Ontario and Quebec by means of a converter station, and this is being considered. A converter station functions by rectification (conversion from alternating current to direct current) of power from the one system and its inversion (conversion from direct current to alternating current) into the other system. While a converter station is costly, it permits power flow in either direction to be controlled in a smooth, flexible, and rapid manner. Costs have dropped in real terms in recent years due to the development of solid-state technology. A converter station might also be used in lieu of a synchronous interconnection, although the cost might be

difficult to justify. Apart from considerations of cost, a converter station is superior to a synchronous interconnection in many respects.

It is also possible to split a converter station, with the rectifier and converter sections joined by many miles of direct-current line or cable. Direct-current lines and cables are more compact and less costly than alternating current lines and cables. But because of the cost of the converter stations, a direct-current link is more economic than an alternating-current link only for interconnections involving some hundreds of miles of overhead line, or some tens of miles of cable. The conceptual plan described in the "Report to Interprovincial Advisory Council on Energy" (IPACE) by the IPACE Networks Study Group in October 1978 contemplates a 3,000 MW direct-current link between Winnipeg and Sudbury, and this link might also serve to strengthen interchange capability between the East System and the West System of Ontario Hydro.

Strengthened interconnections with the United States will probably be in the form of 500 kV alternating-current lines; however, direct-current links are also likely to be considered.

Notes to Chapters

Notes to Chapter Two

1. Royal Commission on Electric Power Planning. *Report on the Need for Additional Bulk Power Facilities in Southwestern Ontario*, June 1979, and *Report on the Need for Additional Bulk Power Facilities in Eastern Ontario*, July 1979.

2. In AC circuits, due to the reactance of circuit elements such as transmission lines, transformers, and motors, the voltage and the current are generally "out of phase", that is, they peak at different times. As a result, power in AC circuits has two components -- the active or real power, measured in watts and the reactive power, measured in volt-amperes (reactive). Unlike real power, which is commonly referred to as power, reactive power cannot be used to perform work and its production, except for any additional losses it may create, does not consume energy in the form of fuel or falling water.

The presence of reactive elements in an AC power system may cause the voltage levels across the system to change substantially as the power demand changes. In order to maintain satisfactory voltage levels, provision to control reactive power must be made in the design and operation of a system. This is referred to as reactive power compensation.

See the *Report on the Need for Additional Bulk Power Facilities in Eastern Ontario* (RCEPP, July 1979) for a discussion of voltage control.

3. Note the distinction between base load and the base-load mode of operation of a generating station. The operating mode of a generating station is defined in terms of its capacity factor, which is the ratio of the average power generated by a station to the station's peak capacity. The definition of various operating modes is rather arbitrary. Ontario Hydro defines base-load mode as annual capacity factors (ACFs) of more than 55 per cent, intermediate-load mode as ACFs between 55 and 10 per cent, and peak-load mode, or peaking, as ACFs of less than 10 per cent.

Notes to Chapter Three

1. S. Banerjee and L. Waverman. "Life Cycle Costs of Coal and Nuclear Generating Stations". A study commissioned by the RCEPP, July 1978.

2. Ontario Hydro. *Cost Comparison of 4 × 750 MW Fossil-Fuelled and 4 × 850 MW CANDU Nuclear Generating Stations*

3. The loading order refers to the order in which generating units are loaded, to supply the changing demand. Units with low fuel cost, such as nuclear and base-load hydraulic, are loaded first and supply the base load. Those with higher fuel cost, such as oil and gas, are loaded only during peak periods or to provide reserve. Thus, the capacity factor of a unit declines as it moves up in the loading order. Loading order is sometimes referred to as merit order or stacking order.

4. For a description of these terms and other terms used in this section, see the section entitled "Availability and Security in the Generation Subsystem" in Chapter 4.

5. Sierra Club of Ontario. "Planning Electric Power for Ontario". Submission to the RCEPP, September 1978. RCEPP Exhibit 369, p. 61.

6. While Bruce is essentially an 850 MW reactor, its electrical generating capacity is only 750 MW, because part of the steam is supplied to the heavy-water plants.

7. R.L. Scott. "Outages at Light-Water-Reactor Power Plants: A Review of 1973-1977 Experience", *Nuclear Safety*, vol. 20, no. 2, March-April 1979, p. 211.

8. RCEPP transcript vol. 300, p. 44952.

9. 1,000 BTU/lb is equivalent to 2.33 MJ/kg in S.I. units. Thus the heat contents of the western Canadian and U.S. bituminous coals are 25.63 MJ/kg and 30.3 MJ/kg, respectively.

10. RCEPP interrogatory no. 21-26.

11. RCEPP transcript vol. 39, p. 4894.

12. Sierra Club of Ontario. *Op. cit.*, pp. 80-81.

13. *Ibid.*

14. Ontario Hydro. "Generation Planning Process". Submission to the RCEPP, May 1976. RCEPP Exhibit 21.

15. The operating limitations of the CANDU reactors at low capacity factors refer to their limited capability in daily load-following. In isolation, a CANDU unit, or any unit for that matter, can be run at

any low annual capacity factor simply by running it at full output over a given time and shutting it down for the rest of the year.
16. RCEPP transcript vol. 236, pp. 37380-37384.
17. Ontario Hydro. *Op. cit.*, p. 50.
18. RCEPP transcript vol. 235, pp. 37279-37281.
19. Ontario Hydro. *Op. cit.*
20. Ontario Hydro. "Total Electric Power System". Submission to the RCEPP, October 1978. RCEPP Exhibit 375, p. 12.

Notes to Chapter Four

1. The difference between the availability and the capability factor of a unit may be explained as follows. Availability takes into account the capability as well as the factors external to the unit, such as fuel and water shortages and strikes. Therefore, availability is usually less than or equal to the capability of a unit. In the absence of any external restraints, availability and capability may be used interchangeably.
2. *Report on the Questionnaire on Generating Capacity Reliability Evaluation*, prepared by the Power System Reliability Committee, Canadian Electrical Association, March 1975. The results of this survey were also reported by R. Billinton in his submission to the Ontario Select Committee on Hydro Affairs on March 21, 1976.
3. The discussion of the LOLP methodologies of the three utilities is based on the information obtained through the 1975 survey indicated in Note 2. While we are aware of some subsequent changes in Ontario Hydro's methodology, we do not know of any recent developments in reliability evaluation in Hydro-Québec or in Manitoba Hydro. The changes in Ontario Hydro's methodology will be discussed in subsequent sections.
4. Ontario Hydro. "System Expansion Program Reassessment Study". Final Report, February 1979. Also see interim reports 2 and 5 published in November 1978.

Notes to Chapter Five

1. Ontario Hydro. "Hydroscope", July 27, 1979, vol. 16, no. 15.
2. Ontario Hydro. "Total Electric Power System". Submission to the RCEPP, October 1978. RCEPP Exhibit 375. Since Ontario Hydro's submission in October 1978, the accident at the Three Mile Island nuclear reactor has opened up the possibility of firm exports to Pennsylvania. Ontario Hydro and General Public Utilities (GPU), the owner of the TMI plant, are negotiating a contract under which Ontario Hydro would export 1,000 MW of firm power to GPU over the period 1985-90. The power would flow from the coal-fired Nanticoke Generating Station via an underwater cable (200-400 kV) to Erie, Pennsylvania. This would interconnect Ontario Hydro with a new power pool, that is, the Pennsylvania-New Jersey-Maryland pool. It is believed that the capital cost of the cable would be recovered in a couple of years.
3. *Ibid.*
4. RCEPP. *Report on the Need for Additional Bulk Power Facilities in Eastern Ontario.* July 1979, pp. 96-7.
5. U.S. Department of Energy, and Energy, Mines and Resources Canada. "Canada/United States-Electricity Exchanges". May 1979.
6. Energy, Mines and Resources Canada. "An Energy Strategy for Canada: Policies for Self-Reliance". Ottawa, 1976.
7. "An Evaluation of Strengthened Interprovincial Interconnections of Electric Power Systems". Report to Interprovincial Advisory Council on Energy by IPACE Networks Study Group. October 1978.
8. *Ontario Hydro Statistical Yearbook, 1977.*

Notes to Chapter Seven

1. Ontario Hydro. "Load Forecasting". Submission to the RCEPP, May 1976. RCEPP Exhibit 19, table 4.
2. Ontario Hydro. "Survey on Power System Reliability: Viewpoint of Large Users". Report No. PMA 76-5, April 1977. See also the discussion on the costs and benefits of reliability in Chapter 4. Some customers, such as hospitals, computer installations, and certain processing industries, have their own stand-by generation to ensure essential services and to prevent adverse effects in vulnerable processes.
3. RCEPP transcript vol. 236, p. 37381.

4. Ontario Hydro. "Generation Planning Processes". Submission to the RCEPP, May 1976. RCEPP Exhibit 21, pp. 65-7.
5. *A New Public Policy Direction for Ontario Hydro.* Final report of the Select Committee of the Legislature Investigating Ontario Hydro. June 1976.
6. For an example of the methodology used earlier, see "Planning of the Ontario Hydro East System". Ontario Hydro Report 573 SP, June 1976.
7. The 1,100 MW and 600 MW of co-generation capacity refers to the type of in-plant generation by which steam produced for process purposes is passed through a turbo-generator to produce electricity as a by-product. Other types are co-generation potential, requiring investment in new steam facilities, and self-generation of power by firms or institutions that have no process-steam requirement. The total technical potential in 1985 of the three types of in-plant generation is estimated by Ontario Hydro to be 1,125 MW, 765 MW, and 1,730 MW respectively.
8. Ontario Hydro. "1979 Review of Generation Expansion Program". March 1979.
9. Ontario Hydro. "System Expansion Program Reassessment Study". Final report. February 1979, p. 17.
10. Ontario Hydro. *Op. cit.*, p. 9.11.
11. *Ibid.*, p. 5.4.
12. RCEPP. *Report on the Need for Additional Bulk Power Facilities in Southwestern Ontario.* June 1979, p. 95.
13. *Ibid.*, p. 85.
14. Ontario Hydro. *Op. cit.*, p. 13.14.
15. Ontario Hydro. "Transmission Planning Processes". Submission to the RCEPP. RCEPP Exhibit 22, June 1976.
16. For a detailed discussion of the issues related to bulk power transmission planning in southwestern and eastern Ontario, see the RCEPP's *Report on the Need for Additional Bulk Power Facilities in Southwestern Ontario*, June 1979, and *Report on the Need for Additional Bulk Power Facilities in Eastern Ontario*, July 1979.
17. *Ibid.*
18. N. Hingorani. "The Re-emergence of DC in Modern Power Systems", *EPRI Journal*, June 1978.

Notes to Chapter Eight

1. Ontario Ministry of Energy. *Ontario Energy Review.* June 1979, p. 31.
2. Ontario Hydro. "Electricity Costing and Pricing Study". October 1976. The OEB submitted its *Report to the Minister of Energy on Principles of Electricity Costing and Pricing for Ontario Hydro* on December 20, 1979. The OEB concluded that "the concept of time-differentiated rates is consistent with the fairness objective" (p. viii) and recommended that "the concept of time-differentiated rates be introduced at both the bulk power and retail levels" (p. 36).
3. RCEPP. *Interim Report on Nuclear Power in Ontario.* September 1978, p. 20.
4. Ontario Hydro. "1979 Review of Generation Expansion Program". March 1979.
5. RCEPP. *Report on the Need for Additional Bulk Power Facilities in Eastern Ontario.* July 1979, pp. 90-91.
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11. "Ontario Hydro Underground Pumped Storage Study". Acres Consulting Services Limited, Niagara Falls, Ontario, January 1976.
12. *Ibid.*, p. 6.
13. *Ibid.*
14. Letter to Dr. W. W. Stevenson of the RCEPP from G. F. McIntyre of Ontario Hydro's Resources Planning Department, September 4, 1979.
15. Ontario Hydro. "Total Electric Power System". Submission to the RCEPP, October 1978. RCEPP Exhibit 375, p. 11.
16. *The Economics of Industrial Co-Generation of Electricity.* Proceedings of a seminar co-sponsored by the Ontario Ministry of Energy and Ontario Hydro. December 1978.

17. *Ibid.*, paper by Donald D. Dick.

18. Comments by Ontario Hydro on the Middleton Associates November 1977 report entitled "Alternatives to Ontario Hydro's Generation Program". June 1978.

19. Vol. 5 of this Report.

20. See the paper by A. Juchymenko in the seminar proceedings referred to in note 16.

21. See the paper by A. Gusen in the seminar proceedings referred to in note 16.

22. See the paper by D.A. Drinkwalter in the seminar proceedings referred to in note 16.

23. Ontario Hydro. "Development of Industrial Co-Generation in Ontario". Report ECD-78-8. November 1978, p. 11.

24. See "Cost of Production of Electricity with Wood By-Products: Hearst Study" in the seminar proceedings referred to in note 16.

25. "Wood-Fired Electricity Generation in Eastern Ontario". Study prepared for the RCEPP by Morris Wayman Limited. July 1978.

26. Ontario Hydro. "Wood as a Fuel for Electric Power Generation in Ontario Hydro's System". Report 79207, August 1979.

27. Ontario Hydro. "Generation-Technical". Submission to the RCEPP, March 1976. RCEPP Exhibit 2, p. 2.2-37.

Notes to Appendix B

1. It is recognized that the study's estimates of the additional security force are too high. However, since they do not affect the nuclear-coal comparison to any significant degree, no attempt was made to revise them.